In The Matter Of:
U-21870

U-21870 Transcript v3 Cross Exam 11.04.25
November 4, 2025



STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application
Of CONSUMERS ENERGY COMPANY for
Authority to increase its rates
For the distribution of natural — Case No. U-21870
Gas and for other relief — Volume 3
_____/ — Public Record

Proceedings held via Microsoft Teams in the above-entitled matter before Jonathan Thoits, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Tuesday, November 4, 2025, at 10:00 a.m.

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(On the record at 10:14 a.m.)

THE COURT: We are on the record in case U-21870, titled in the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief. My name is Jon Thoits, I'm the presiding officer for this matter. This is the date and time for the hearing in this case, it is also the date and time for a motion to strike. This hearing is being held by video and audio conference.

Could we have appearances, please? First on behalf of consumers energy.

MR. GENSCH: Thank you. Good morning, Your Honor, Gary Gensch on behalf of Consumers Energy, and I'm also entering the appearance of Bret Tororaitis and Anne Uitvlugt, Spencer Sattler, and Evan Keimach. Thank you.

THE COURT: Do we have an appearance on behalf of the public service commission staff.

MR. SONNEVELDT: Yes, Your Honor. At this time, I would like to enter my appearance, Daniel Sonneveldt along with the appearances of Alena Clark, Michael Orris, Nicholas Taylor, Amit Singh and Adam Cozort.

THE COURT: Thank you. Do we have an appearance on behalf of the Michigan Attorney General?

MS. GILL: Good morning, Your Honor. Celeste Gill on behalf of Attorney General Dana Nessel, also filling appearances in the case, Lucas Wollenzien and

FIX Michael lone.

THE COURT: Thank you, do we have an appearance on behalf of the Association of Business Advocating Tariff Equity or ABATE.

MR. Campbell: Morning, Your Honor. Steve Campbell on behalf of the Association of Businesses Advocating Tariff Equity.

THE COURT: Thank you. Do we have an appearance on behalf of Citizens Utility Board of Michigan?

MR. BZDOK: Good morning, Your Honor. If I may enter an appearance on behalf of Citizens Utility Board of Michigan, as well as the other three aligned parties?

THE COURT: Sure.

MR. BZDOK: Thank you. Your Honor, Christopher Bzdock, along with Holly Hillyer, and Tracy Jane Andrews on behalf of Michigan Environmental Counsel, Natural Resources Defense Counsel, Sierra Club, and the Citizens Utility Board of Michigan.

THE COURT: Thank you. Do we have an appearance on behalf of The Ecology Center, The Environmental Law and Policy Center, The Union of Concerned Scientists, and Vote Solar?.

MR. ABRAMS: Good morning, Your Honor, Daniel Abrams, appearing on behalf of The Ecology Center, The Environmental Law and Policy Center, The Union of Concerned Scientists, and Vote Solar. Collectively

referred to as the clean energy organizations. And I'd also like to place an appearance on the record for my colleague Katie Duckworth. Thank you.

THE COURT: Thank you. Do we have an appearance on behalf of The Energy of Michigan?

Hearing none. Do we have an appearance on behalf of The Foundry Association with Michigan?

Mr. Kesky, do we have an appearance on behalf of Great Lakes Renewable Energy Association?

MR. KESKEY: Good morning, Your Honor, Dan Keskey, appearing on behalf of The Great Lakes Renewable Energy Association.

THE COURT: Thank you. Do you have an appearance on behalf of Hemlock Semiconductor Operations and Solar Technology?

MS. HESTON: Good morning, Your Honor. Jennifer Heston of the Potomac Law Group appearing on behalf of Hemlock Semiconductor Operations, LLC and Solar Technology LLC.

THE COURT: Thank you. Do we have an appearance on behalf of Kroger?

MR. BOEHM: Good morning, Your Honor. Hurt Boehm appearing on behalf of The Kroger Company.

THE COURT: Thank you. Do we have an appearance on behalf of the Michigan Elec -- Electric Transmission Company?

MR. JOSH KLUZAK: Yes, Your Honor, Josh KluZak appearing on behalf of Michigan Electric Transmission Company. I would also like to enter the appearance of Richard Aaron, Courtney Kissel, Olivia Flower, and Hannah Buzolits.

THE COURT: Thank you. Do I have an appearance on behalf of the Michigan Energy Innovation Business Council, and The Institute for Energy Innovation, and Advanced Energy United?

Hearing none. Do we have an appearance on behalf of Urban Core Collective?

MR. TEMPLETON: Yes, Your Honor. Mark Templeton of The Abrams Environmental Law Clinic entering an appearance on behalf of Urban Core Collective. Also entering an appearance on behalf of my colleague Jacob Schuhardt.

THE COURT: Thank you. Do we have an appearance on behalf of Walmart?

MS. HORNE: Good morning, Your Honor. Melissa Horne on behalf of Walmart, Inc.

THE COURT: Thank you. Do we have any other appearances?

Hearing none. As I indicated, this is the date and time for the hearing with the examination or binding in, but it's also the time for a hearing on the motion to strike. Motion to strike by Michigan Environmental

Counsel and I see and have read that is a response filed by Consumers Energy. Are there any other parties present who filed a response or a pleading in connection with the motion to strike?

Hearing None. Are -- are there -- is there any other party who has a position on the motion to strike?

All right. Hearing none. Mr. Bzdok?

MR. BZDOK: Thank you, Your Honor. I want to offer some framing and comments, and -- and then some specific replies to the response to Consumer's file. I noted in an e-mail earlier this morning that I'm going to refer to certain exhibits that are in the SharePoint that are exhibits discussed in the motion or response. Here are the framing comments, so indirect Consumer Energy presented two capital projects for the Jackson Gas Plant. One is the Generator Step Up or GSU project, and one is a Variable Inlet Guide Van or VIGV project. In direct, MNSC witness, Tyler Comings identified flaws in the in the economic analysis for those two projects and he recommended disallowances. In rebuttal, Consumer's witness Richard Blumenstock agreed with Mr. Comings that those flaws were accurate, accurately represented. Agreed that the flaws, conceded the flaws. And then he sponsored new evaluations and new concept of approvals and that's critical. They were not revised approval documents. They were not revised evaluations. They were new evaluations

and new approval documents for the GSU Project, Exhibit A-45, which is in the Consumer's SharePoint is the concept approval, the original concept approval A-202 is the new concept approval document. They are completely different documents, they're not markups, they're not revisions. The same is true for the VIGV project, MEC-12, which Mr. Comings sponsored is the original approval and evaluation. Exhibit A-203, a rebuttal Exhibit is the new approval and evaluation, not a revision, new documents. This is important, because Consumer's response says otherwise. On page 2, Consumer says on page 2 quote:

"Company witness, Blumenstock responded to this testimony."

Meaning Mr. Coming's testimony.

"By correcting some of the assumptions in his original analysis in order to show that the energy and capacity benefits of the projects nevertheless remain reasonable to justify the costs."

MR. BZDOK: But he did not correct assumptions in his original analysis. They conducted new evaluations and created new project approvals in rebuttal, they're trying to bring them in -- in rebuttal. Not only that, Consumer's use a different modeling program for the new evaluations, so they didn't just redo the evaluations, they use an entirely different computer model to do the evaluations.

You can see this in Exhibit A-202 on page 1, which talks about the GSU project. It says the original business case relied on Aurora modeling and assumptions, and then it says under updated modeling approach, Copperleaf. So they went from Aurora to Copperleaf for the rebuttal documents. Same thing as 203, the rebuttal exhibit on the VIGV project, the economic evaluation. It says on page 1, has been revised from the initial Aurora run to a Copperleaf approach. So new evaluations, new concept approvals using different computer modeling all in rebuttal.

Not only that, Consumers did not only change the assumptions that Mr. Comings identified as flaws, they changed other assumptions as well. This is critical. I don't know if you have A-203 or I can share A-203. It might be -- I could share it, if I could briefly?

THE COURT: Sure.

MR. BZDOK: Thank you. So on my screen is page 1 of exhibit rebuttal, exhibit A-203. If you scroll down in A-203, there is economic impact after they talk about changing from initial Aurora run to Copperleaf approach. It says a single stall -- move this over just slightly, I think. A single stall can cost up to 7.4 million,7.4 million based on a recent event.

So a stall, what is this stall cost? A stall cost was -- was based -- was almost doubled as an

assumption into the model. The more that a stall costs, the more value the project has. Right, so that's a change in the critical input, a big change almost doubling the -- the -- the downside cost that justifies this project in the rebuttal exhibit. So new evaluation, new concepts approval document, project approval document, new computer model used to do all of this and new inputs and assumptions that are more favorable to the projects all in rebuttal. I'm going to stop sharing.

That's not rebutting Mr. Coming's analysis. It's changing other assumptions. It's changing methods. It's creating new documents to rehabilitate the justification for the project which Consumers concedes was flawed. That -- that Mr. Coming's testimony was correct. Changing assumptions -- let me -- let me move on.

So in some framing comments, Mr. Blumenstock did not correct assumptions in the original analysis. This is new evidence, it's evidence that aims to rehabilitate the flawed evidence in Consumers direct case. It's also evidence that attempts to supplement the flawed evidence in Consumers direct case. Some specific replies to Consumers response. Consumers says in the response this is a legal matter only testimony that is quote:

"Merely rehabilitated is improper rebuttal."

Similarly, Consumer says that evidence that rehabilitate direct evidence, but also rebuts another

witness is proper. Consumer doesn't cite any case that says that. That's not what the scheduling memo says. The scheduling memo says rebuttal should be used for the purpose of rehabilitating or supplementing, should not be used for the purpose of rehabilitating or supplementing a party's direct case. Consumers never sought to amend that portion of the scheduling memos directives. Consumers implies support for it position that you can rehabilitate as long as you're also rebutting from the use of the word merely in U-8871, one of the cases I cited. And it's true, that in that case they said one problem was this is trying to rehabilitate testimony.

Another problem is that they didn't specifically identify which testimony that was rebutted, but that case never said if you rehabilitate and rebut, that becomes -- that transforms improper rebuttal to proper rebuttal. Even if that was authority, that position would not apply here because Mr. Blumenstock did not rebut Mr. Comings in a meaningful way. He never said the flaws Mr. Comings identified were wrong, he said if we redo the analysis and we redo the approvals and we take those assumptions and we -- and we input them, and then we also change other assumptions, and we run it all in a new computer program, we'll get a result that's favorable. That's not that's -- not contradicting Mr. Comings.

Other than at the most bottom line conclusion,

the scheduling memo also referenced that I referenced already supplementing, Consumers never references why this is not supplementing its testimony. Why new approvals, new evaluations, new computer modeling and new assumptions would not be supplementing its direct case. The only time they address supplementing is on page 7 of the response. Consumer says, quote:

> "To further supplement these materials, the company intends to include screen captures from the Copperleaf software showing formulas."

MR. BZDOK: Et cetera, et cetera. That they acknowledged that they did supplement. They said we were further -- I mean, what else would further supplementing mean other than the rebuttal documents supplement direct case. And now we're going to further supplement the direct case with the discovery. Consumers talks about some rules of evidence and they say these rules of evidence allow rehabilitation, they do not in this circumstance or any circumstance related to this. They talk about MRE 608A, that's rehabilitation of a witness's character for truthfulness -- that -- I've known Mr. Blumenstock since 2012. I -- I don't doubt his truthfulness. We didn't attack his truthfulness, we wouldn't do that. It has -- that really has nothing to do with the situation of facts presented.

It -- 613B, talks about prior inconsistent

statements. There was no issue in our testimony about prior inconsistent statements. These are rules about what you do after cross-exam. And this is -- there's been no cross exam. These rules are wholly inapplicable to this situation. The same is true of the use of definition from Black's Law Dictionary, that again talks about witness credibility which we've not raised. They use a statement from an informant on evidence which talks about credibility and which talks about disapproving impeaching facts. None of those scenarios, none of those facts are present here. Those rules are wholly inapplicable. And I think the -- the -- the -- the -- the share inapplicability of those rules, a -- and -- and the fact that Consumers is attempting to rely on them really points to the lack of authority for the company's position.

They also say, well, well, Mr. Comings opened the door because he said Consumer should redo their analyses. They should redo them in the next case. They can come back to the next case and ask for recovery based on better analyses that are accessible to the parties and they're introduced on direct. This happens all the time in commission proceedings. We had three or four cases like that involving River Rouge major maintenance and routine capital expenditures a few years ago. The commission says no, you didn't do the analysis you needed to do or you didn't do it right. You can come back and

present it in your next case. They can do that here. Mr. Comings doesn't say re-do your analysis and rebuttal, use new assumption, use new computer models, and then we'll try to figure that out in the 8 days we have after rebuttal gets filed. It's -- it's wholly -- it's wholly improper sequencing for a case.

I want to talk about the Copperleaf modeling a little bit, because that's important. And, again, I think the response inaccurately portrays the situation. Even if Consumers could introduce new evaluations and new project approval documents using different assumptions and a different modeling program, we don't have access to that program and we don't have the calculations. Consumers has not provided the actual -- actual calculations done in the new evaluations of these projects. They provided some calculations in Excel for a different project that's referenced in the response of MNSC-CE-0224, but that's not these projects. They produced some descriptions of formulas and methods and screenshots. Those screenshots are the proposed Exhibit MAC-38 and 39. We cannot replicate their outcomes from those screenshots.

There is not information that -- that can be used to calculate these outputs in those screenshots or in the -- they -- they gave us a couple of Excels with like PSCR data. We cannot reproduce their results. If the results were reproducible from those screenshots and

descriptions of formulas, they could have provided the calculations to us. They wouldn't have needed Copperleaf, they wouldn't be -- they -- they wouldn't have to say, well, you can't have this because it's in -- in Copperleaf and we can't -- we can't reproduce it.

If -- if the formulas were enough, Consumers could have produced the calculations in Excel and they did not even provide all the relevant data in the screenshots. And here I want to refer you to another exhibit and this is MEC proposed MEC-39 and this is -- this is -- this is the screenshots that were provided for the VIGV project. If -- if -- if -- wait a minute, I think maybe I want to refer you to -- I -- I'm sorry. I don't want to refer you to that. I want to refer you to A-202. I want to refer you to A-202, which is the revised -- which is the new, it's not the revised, it's the new project approval and evaluation for the GSU. May I share gain Your Honor?

THE COURT: Yes.

MR. BZDOK: So here's 8202 again, and on page 1 A-202, Consumers explains that -- that basically they did this analysis by creating a probability curve that increased by five percentage points annually through December 2039. So, in other words, this is an analysis that looked at the risk of failure for a period of, you know 13 or 14 years from now, right. And did the analysis. And then if you go down in this same document

and you go to the last page of this document, you will see that the that the -- the -- the output that was presented here has a loss generation risk for only three years. It has a financial risk for only three years, it has an investment cost for three years, okay. So we didn't even get -- we didn't even get the input for the full period of time of the analysis.

Finally last comment, the response says, well, our -- our -- our concerns about the discovery. Not the calculations not being provided are premature because Consumers was going to provide us with those in discovery, that's infuriating, right? The -- the rebuttal was due. The rebuttal came in on the 21 of October. The motions to strike were due two days later. There's no way we can manage this. When we get entirely new evaluations with entirely new modeling and entirely new inputs and assumptions and then we can do discovery on a 5 day turnaround, there's no way -- I don't know. And -- and then we have a motion to strike due in two days. There -- there's -- there's no way we cannot -- we -- we have to we have to file it. We can't wait for the discovery or the motion to strike and when we did get the discovery, it was not usable to replicate or reproduce what was presented.

So in sum, Consumer's new evidence is improper rebuttal. It rehabilitates the company's direct case.

It's supplements the company's direct case and we have no model -- access to the modeling used to create it or the calculations necessary to evaluate it and for these reasons which are independent, each reason alone is enough. We would ask that this testimony in exhibits be stricken. Thank you.

THE COURT: So, Mr. Bzdok, it sounds like discovery was received?

MR. BZDOK: Discovery was received. That did not include materials requested. It did not include calculations. Did not include anything that could be reproduced. Did not include access to the model used to create the new analysis. So -- so documents were received but they were they did not provide what was requested.

THE COURT: All right. Thank you.

MR.TOTORAITIS: Your Honor, this is Bret Totoraitis. I'll be handling the oral argument on this.

THE COURT: All right. Thank you.

MR.TOTORAITIS: Your Honor, I think I'm going to start with Mr. Bzdok's response to your very most recent question. I disagree with Mr. Bzdok's representation that -- that MEC did not receive what it asked for in its most recent discovery.

One of the things Mr. Bzdok mentioned is that they didn't receive access to the model. They did not ask for access to the model. So, of course they would not

have received it -- it would be false to represent that consumers energy is unable to give them access to the model. They did not ask for it.

So, just as a clarification of Mr. Bzdok's response, Consumer's Energy in its discovery, provided to MEC all that it had, all that it was capable of producing with respect to the model, responsive to what was asked for. The -- the model itself does not show -- it doesn't display, it doesn't allow an output that shows the calculations. Like many pieces of software, it makes calculations behind the scene. It put -- inputs into the model, the model turns out a result, we provided to Mr. Bzdok everything that we had that we could. And they did not ask for access to the model, though we -- we could arrange for that, had they asked.

So I -- I just want to make sure to clarify that in his initial comments, Mr. Bzdok emphasized over and over and over again that the analyses that were provided is part of rebuttal in this case. The -- the concept approval documents were new, that they had been done with new software Copperleaf instead of Aurora. It is the original ones were done, that the concept approvals themselves were new, new, new, new. He -- he -- he emphasized over and over and over again that everything was new, but that's where rebuttal is. Rebuttal is new. Rebuttal is a response to an argument that another party

makes. I -- I -- I would beg Mr. Bzdok to show us rebuttal that doesn't include, new info, new analyses, new materials. There's always something new in rebuttal. That's the whole point of rebuttal, that's responding to an argument that previously had not been raised. Mr. Bzdok claims that the materials provided in Mr. Blumenstock's rebuttal did not rebutt Mr. Comings in any meaningful way. I -- I think that best the question why he's arguing so strenuously for it -- for its exclusion.

Mr. Comings attempted to make a case, that due to some assumption defects, assumption -- what he -- he perceived as errors in the assumptions included in the original concept approval documents. That consumers energy could not make out a case that these two projects, the Variable Inlet Guide Vane Project, and the s -- the Generator Step Up Transformer Project for the Jackson Generating Station were economically reasonable. And the concept approval documents that were put forth in rebuttal do exactly that. They are analyses that address the assumptions that Mr. Comings identified as lacking and put forth an analysis with those assumptions in order to show that these projects remain economically reasonable. It's valid evidence. It does respond to Mr. Comings and the fact that it's new.

I think what Mr. Bzdok is attempting to do is leverage on some recent commission decision. Where

parties have tried to insert wholly new projects with only new spending into rate cases and -- and substitute those things in for other projects that may have become deprioritized, or what have you. And so, the fact that the commission has in recent cases concluded that that type of evidence is not appropriate rebuttal because they're wholly new projects. I think Mr. Bzdok is just leveraging on the fact that the word new got used and trying to make the -- the case that nothing new can ever be adequate rebuttal. If that were true, if rebuttal were confined to the exact same words, analyses, and facts that were contained in the direct testimony, what would be the point of rebuttal? It -- there would be no point.

Mr. Bzdok argued that my reference in the company's response to some of these court rules and some of the language out of some evidence treatises and things like that show a lack of legal support for the company's position. But the reality is, all the legal support the company's position needs is found right in the case that -- that MAC cited itself. It's in U-8871. It's the commission's case where it defined -- I don't know if that was the first time they defined it, but they certainly in that case defined what constitutes rebuttal, and they've relied on that same definition of rebuttal for many decades since. And you need only look at the definition of rebuttal.

Mr. Bzdok has tried to make this case that somehow if your rebuttal is also rehabilitative or if it's also supplementary, that rebuttal is not rebuttal anymore and that has never been the commission's holding as far as I could find anywhere. The only case he cites for support for that is U-8871 and when you analyze that case, you can see that there was more going on there. That -- that the commission did not conclude that there was rebuttal happening there, because there was no identification of a thing being rebutted. Here we have identification of a thing being rebutted. Here, Mr. Blumenstock's testimony does meet the definition of rebuttal. It may also be rehabilitation and -- and -- and that's the argument that Mr. Bzdok tries to address. Those other citations, I agree they're not necessarily applicable to this argument, but the -- what they do show is that rehabilitation is not -- is not in and of itself an improper thing to do in a case.

Anyway, Mr. Bzdok tries to make it as if rehabilitation once it occurs nullifies rebuttal and -- and I don't see that he has ever identified a single legal sup -- source that supports that theory or that argument. So what he -- what Mr. Bzdok is really doing more than anything here without saying it, is he is bemoaning the tight time frame that is set in statute for litigating electric rate cases. And I'm not unsympathetic

to the fact that Mr. Bzdok has little time to respond after rebuttal because of the tight schedule. I -- I appreciate that fact, but that's just a matter of law. That is something that is beyond the control of any of the people that are participating in this hearing today. And I would emphasize too that in an electric rate case, it is the utilities constitutional right to earn rates that can provide compensation for expenses and fair rate of return that's at stake. It's Consumer Energy's constitutional rights that are at stake and as difficult as this tight schedule in -- in a 10 month rate case time frame may be for Mr. Bzdok, because it's the company's constitutional rights that are at stake.

The legislature has seen fit to -- to provide for a short turnaround the -- the commission through its rules of practice and procedure, have seen fit to establish a procedural methodology that gives the utility what is often the last word in rebuttal testimony and -- and it is difficult, but it's not legally improper. Mr. Bzdok still has the opportunity to cross-examine Mr. Blumenstock about anything that was included in his rebuttal testimony if he sees fit.

All of Mr. Bzdok's arguments really go to the weight of the evidence, not to its admissibility. He's not -- other -- other than trying to leverage on some arrant words in an old MPSC order, he's really not

offering you any argument that relates to the general admissibility of the typical admissibility of evidence at all.

So, Your Honor, Consumers Energy would argue that this is perfectly proper rebuttal testimony and we would ask that you would deny the motion to strike. And Mr. Bzdok will have his opportunity to question Mr. Blumenstock tomorrow.

THE COURT: Well before we do that, Mr. Totoraitis, just one question. On page 5 of Consumer's response, there's kind of a summary statement, my phrasing. Regarding one of your positions here where you write:

> "It is clear there's no general prohibition on using rebuttal testimony to rehabilitate a witness's testimony so long as his testimony is in fact rebutting something at the same time."

I note that neither there nor anywhere else that I could find in your response, do you cite any authority for that proposition obviously from your argument here as well as your response to you -- evaluated some legal authority that was referenced that relates to this issue. Do I take it that you were unable to find any authority which supports that summary statement that I just quoted?

MR.TOTORAITIS: No, Your Honor. I would point to case number U-8871, in which The Commission defines

what constitutes proper rebuttal and does not, contrary to Mr. Bzdok's argument. Does not make out a claim that merely because something is rehabilitative, it fails the definition of of rebuttal testimony. This testimony meets the definition of rebuttal. That is the authority that we're relying on in this -- this case that Mr. Bzdok cites does not stand for the proposition that if at also happens to be rehabilitative it renders proper rebuttal improper. It does not say that. That is his case. I've and I've analyzed his case. It does not support the proposition he holds it out for.

THE COURT: But does it state or even imply the proposition that you are asserting in your response?

MR.TOTORAITIS: Yes. It -- it states that if you meet the definition of rebuttal then that's proper rebuttal.

THE COURT: But does it address rehabilitation?

MR.TOTORAITIS: The only thing that it says about rehabilitation is that something offered in rebuttal testimony may not be merely rehabilitative. This is not merely rehabilitative.

THE COURT: All right, thank you. Mr. Bzdok?

MR. BZDOK: Thank you. Brief replies on a couple of things.

First of all the discovery that was provided. The discovery that was provided has been loaded in the

MNSC hearing folder under Mr. Blumenstock, MAC-38.

Question 5A:

"Please provide all supporting documents work papers and analyses used in developing this new concept approval in electronic format with formulas in tech were applicable."

The response says:

"We can't do it but here are some screenshots from the software program and here is a description of how the program works."

"Provide the supporting calculation for all MPVs in electronic format with formulas intact."

The response says:

"We cannot do that. We have no further MPV support other than screenshots from the program and a description of how the program works."

MEC-39:

"For the other new approval provide all supporting documents, work papers, and analyses used in developing this new concept approval in electronic format with formulas intact where applicable.

Response says:

"We can't do that, but you can have clippings of screenshots, I would say, of what our modeling programs has on the computer screen when it describes its process."

B:

"provide the supporting calculation for all MPVs in electronic format with formulas intact.

Consumers says:

"The concept approval and the MPV calculations are performed in Copperleaf, no other MPV support is available in electronics format other than the discussion of how Copperleaf models MPV. We can describe for you how it works, we can show you screenshots of steps along the way."

You can't have any analysis. You can't have any calculations. You can't have anything you can replicate or reproduce.

Next, I guess the last thing is the tight time frame. The timeframe is relevant, because the commission's decisions about improper rebuttal, specifically talk about the fair or unfair ordering of proofs. That is the rationale for why you cannot rehabilitate and supplement your direct case in rebuttal. Because it -- I'm not complaining about the timeframe. We -- we do the best we can with the time frame, everybody does and -- and -- and that isn't given, but because the timeframe is so tight, because there is generally not surrebuttal, because there is generally not time to do you know more than one round of -- of a very quick discovery. It is critical to the fair ordering of proofs.

That -- that -- that -- that parties not supplement, that they not introduce new material, that they not run new analyses using different assumptions, and new computer programs in that very short amount of time that's left. That's not the fair ordering of proofs. And that's what the commission has said as a -- as a basis and a rationale for the rules against rehabilitating or supplementing in rebuttal. We -- we -- and -- and I will -- I will cross examine Mr. Blumenstock if needed, but, you know, I'm not a miracle worker. We put a lot of effort in, but we can't you know, there's only so much we can do when we're presented with brand new stuff, new assumptions, new methods, and we can't have the calculations. There's only, there's a limit on what we can do, and that's all I have to say, Your Honor.

MR.TOTORAITIS: May I respond one last time?

THE COURT: You may.

MR.TOTORAITIS: The calculations that Mr. Bzdok says he cannot have, he can't have because we don't have them. The -- the software does what it does and we could -- if Mr. Bzdok's expert was interested in attempting to utilize the software and running some sample scenarios of his own or whatever he wanted to do, we could have. And would have been willing to make that available to him. He did not ask. Those calculations, Consumers Energy doesn't have them. I -- I can tell you that

Consumers Energy doesn't purchase software for use unless it's tested to try to validate the accuracy. And Consumers Energy has this this software, this Copperleaf is utilized as I understand it, by more than 70 utilities across The United States Of America for this type of modeling. It's -- it's a popular, well relied upon software, Consumers Energy did before purchasing it, test the software against known values. To see if the values that it produces are reasonable and concluded that it was reasonable.

Mr. Bzdok has sufficient information, assuming that his witness has appropriate expertise. He does have sufficient information to test the reasonableness of the outputs. And I noticed that Mr. Bzdok has never suggested that the outputs from this model appear unreasonable. So as the evidentiary issue there's that.

As to the fair ordering of proofs, I would say This, there is always an endpoint. In every case where the evidence -- the collection of evidence has to cease, discovery has to cease. There is that in this case. There's the -- the cases in which the commission talks about the fair ordering of proof, unanimously that I'm aware of, deal with instances as I suggested before where a party has tried to introduce a new project. An entirely new project. An entirely new spending category in rebuttal. And there the commission has recognized that

the fair ordering of proofs is -- is undermined by allowing that. And that makes sense, because then the parties never would have had any opportunity to evaluate or test the -- the rationale behind that project. At any point other than in cross exam. That's not the case here, the -- the site spare GSU project and the VIGV project have been in this case from the beginning. Mr. Bzdok has had an opportunity to test it, there was some validity to some of their testing. The company responded in rebuttal appropriately and Mr. Bzdok seems to be upset that his testing has been successful and that nevertheless the project may be warranted. It seems that he's more interested in disallowance of a project than it getting at the truth. And -- and that I would argue is -- is the reason we're arguing this motion today. That's all I've got.

MR. BZDOK: Your Honor, I -- I really feel I have to respond to that last comment. I know we're testing your patience.

THE COURT: All right.

MR. BZDOK: So now we have gone from we have no authority for Consumer's position, that you can rehabilitate as long as you rebutt too. And what we're left with is now we're -- we're getting inside my head about what my emotions are or what my motivation is for doing something. I mean, we're -- we're sort of beyond

the pail here at this point. Th -- th -- this is wholly new evidence, wholly new assumptions, wholly new models and methods and -- and we don't have the calculations and my expert -- expertise should not be in question, because he identified flaws. He identified flaws in the Aurora modeling that was done for these original projects. And so now they tried to redo, they tried to have a redo. They've had to have to redo in a rebuttal pace. And that's not what rebuttal was for. And that's all I have to say.

MR.TOTORAITIS: Very briefly, Your Honor. To the extent that I attributed any ill motive to Mr. Bzdok, I -- I did not mean that. I -- I would retract that.

THE COURT: All right. Thank you. I've heard Mr. Bzdok say, we asked for this. I've heard Mr. Totoraitis say, you didn't ask for this. So what I would like both of you to do is to send me a copy of the specific discovery request at issue and the response. Together with no more than a two page cover, if you will. Or supplemental argument or brief. Just identifying what was asked and what was provided.

And I recognize we're in the middle of a hearing, but this all should be short and sweet. So I want that to be forwarded to me and filed by the close of business Thursday.

All right. I assume we've been at it for quite

a while, so we will take a break. We'll go off the record for 10 minutes, and then we will come back and start with the cross-exam of Ms. Connolly. We're off the record.

Oh, I'm sorry. Go -- yeah -- go ahead.

MR. BZDOK: Just a procedural question about your directive, which we will, of course meet. We will submit this information and then, Your Honor will render a ruling. Meanwhile, Mr. Blumenstock is up for examination tomorrow. Obviously the outcome of this motion impacts what happens or not happens tomorrow. And so I'm just putting that procedural issue on the table.

THE COURT: I understand and we will, if it is your desire, we will have Mr. Blumenstock available for additional cross, should the result of the ruling cause you to ask for it.

MR.TOTORAITIS: Your Honor, can I suggest something as well?

THE COURT: Sure.

MR.TOTORAITIS: I have -- I have a suspicion that Mr. Bzdok wouldn't ask certain questions of Mr. Blumenstock if his motion to strike were granted. I -- I do not know Mr. Blumenstock's availability later in this cross-exam period off the top of my head. Let me probe that with him, and maybe what we can do instead is move his cross-examination to a time after you can make your ruling.

MR. BZDOK: I would join that request.

THE COURT: No, that's fine. Another alternative, I was trying to give -- give you all some time, but if you want to speed up the turnaround for this supplemental filing. Which, again, I would think would be short and sweet and therefore quick. We can do that as well. So you tell me.

MR. BZDOK: I think the Thursday deadline is great, and would join Bret's suggestion about pushing Rick back, if that's possible.

MR.TOTORAITIS: Let me explore that and I'll let you guys know what his availability may be.

THE COURT: All right. Thank you both. We're off the record.

(Off the record at 11:06 a.m.)

(On the record at 11:17 a.m.)

THE COURT: All right. We're back on the record. This is -- I want to get into examination of witnesses and it's my understanding the first witness to be examined is Laura Connolly. Is that correct?

MS. UITVLUGT: Yes, Your Honor.

THE COURT: All right. Before we do that, just, I know you all are experienced with this. Just reminder though, that when you start off, if you can just confirm that any testimony or documents that are in SharePoint are available to the witness, make sure the witness has access

to it. And if you could also identify if you think the examination might get into confidential testimony or exhibits. As you all know, if that's the case, we treat that differently. From this perspective those who have not signed and non-disclosure certificate will be asked to leave the hearing and for the duration of the examination, which may touch on a confidential matters. As a matter of fact, you know what, it might be helpful if -- if I could have a anyone here who's present right now, identify themselves if they have not signed a non-disclosure certificate, if you could identify yourself, give me your name.

MS. HORNE: Judge, we have not signed a non-disclosure agreements on behalf of Walmart.

THE COURT: All right. Thank you.

MS. DUCKWORTH: I'm sorry, Your Honor. Jonathan Duckworth, as you know, I'm administrative law specialist, I haven't signed a agreement.

THE COURT: Yeah. Thanks, John. You don't need to.

MS. DUCKWORTH: Okay. Thank you.

THE COURT: Thank you.

MR. BZDOK: Your Honor?

THE COURT: Yes.

MR. BZDOK: Just by way of preview, we will be talking about some confidential documents. Those include

Ms. Connolly's Exhibit A -- let's see -- is -- is it 70? Yep, Exhibit A-70. I also have -- we e-mailed around some confidential attachments as Exhibit MEC-29-C, we sent those around yesterday. It is my hope to have as much discussion on the public record as possible, and so I would hope to do that by identifying either at the time in the exam or perhaps on a break whether certain information contained within those exhibits is itself confidential.

THE COURT: All right. Yeah, that would be helpful. That way, Ms. Horne and anyone else who needs to excuse themselves is only doing so for the narrowest of timeframes.

All right. Finally, I would just remind the attorneys that when they're asking a witness to review testimony or exhibit, please pause for a moment to give them an opportunity to -- to find that. Finally the witnesses will be sworn by the court reporter pursuant to this video conferencing. All parties are waiving any objection to that unless I hear otherwise right now. All right, Mr. Gensch or Totoraitis.

MS. UITVLUGT: It will be me, Your Honor. At this time, Your Honor --

THE COURT: -- I'm sorry, Ms.Uitvlugt. Please proceed, thank you.

MS. UITVLUGT: At this time, Your Honor, the company call Laura M. Connolly to the stand.

THE COURT: Ma'am, you will be sworn momentarily by the court reporter, but at this point, can you -- can you hear me all right?

MS. CONNOLLY: Yes. Can you hear me?

THE COURT: Yes. And you -- you've been able to hear the other attorneys who have spoken so far?

MS. CONNOLLY: Yes, I have.

THE COURT: All right. Sara, if you could swear the witness, please?

THE COURT REPORTER: Yes.

Ms. Connolly, could you please raise your right hand for me? Do you swear that the testimony you're about to give in this matter will be the truth, the whole truth, and nothing but the truth?

THE WITNESS: I do.

THE COURT REPORTER: Okay. Thank you.

(At 11:23 a.m., witness sworn and testified as follows)

THE COURT: All right. Ms. Connolly, could you just confirm that you do not have with you right now any notes, papers, or documents other than pre-filed testimony, or exhibits, or discovery responses from this case?

THE WITNESS: I do have one page of notes. I can put that away.

THE COURT: All right. Ms. Uitvlugt?

MS. UITVLUGT: Thank you, Your Honor.

DIRECT EXAMINATION

BY MS. UITVLUGT:

Q. Ms. Connolly, can you please state your full name and business address for the record?

A. Laura M. Connolly, One Energy Plaza, Jackson, Michigan 49201.

Q. Whom are you appearing in this case>?

A. Consumer's Energy Company.

Q. And what's your role at Consumers Energy?

A. I am the director of regulated pricing.

Q. And did you cause to be pre filed with the commission a document entitled the direct testimony of Laura M. Connolly, which consists of a cover page and 16 pages of questions and answers?

A. Yes.

Q. Did you also cause to be pre filed with the commission the rebuttal testimony of Laura M. Connolly, which consists of a cover page and nine pages of questions and answers?

A. Yes.

Q. Do you have any changes that you wish to make to either your direct or rebuttal testimony?

A. No.

Q. If I were to ask you the same questions today would your answers be the same?

A. Yes.

Q. And are you adopting this as your sworn testimony in this case?
A. Yes.
Q. And did you sponsor any exhibits associated with your direct rebuttal testimony?
A. Yes, I have exhibits with my direct testimony.
Q. And were those Exhibit A-16 Schedule F 2.0, A-16 Schedule F 2.1, A-16 Schedule F 3.0, A-16 Schedule F 4.0, Exhibit A-66, Exhibit A-67, Exhibit A-68, Exhibit A-69, which is a confidential exhibit, and Exhibit A-70, which is a confidential exhibit?
A. Yes.
Q. And do you have any changes you wish to make to any of those exhibits?
A. No.
Q. And were those exhibits prepared by you or at your direction?
A. Yes.
Q. Thank you, Ms. Connolly, at this time, Your Honor, I would move to bind in the direct and rebuttal testimony of Ms. Connolly and move for the admission of her exhibits at the end of cross-examination, and I would tender the witness for cross.

THE COURT: Thank you. Are there any objections to the admission of the direct and rebuttal testimony on this witness?

Hearing none. The direct and rebuttal testimony of Laura Connolly is bound into the record.

(At 11:26 a.m., the Direct and Rebuttal Testimony of Laura Connolly is bound into the record)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

LAURA M. CONNOLLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Laura M. Connolly, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Regulated Pricing in the Rates and Regulation Department.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Business Administration degree in Finance in December 2000 from the University of Michigan – Flint. In January 2001, I joined Consumers Energy as a Rate Analyst in the Revenue Requirements section of the Rates Department, where I held positions of increasing responsibility. I joined the Cost Analysis, Pricing and Tariff section of the Rates Department in 2012 and was promoted to Director of Regulated Pricing in July 2021.

Q. What are your responsibilities as Director of Regulated Pricing for Consumers Energy?

A. In my current role I oversee the development of the Company's Cost-of-Service Study ("COSS"), load research, rate design, and other rate-related analyses.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have filed testimony in the following cases:

Case No. U-12575-R	Gas Cost Recovery Reconciliation;
Case No. U-13220	Gas Cost Recovery Plan;
Case No. U-13570	Gas Cost Recovery Plan;
Case No. U-13570-R	Gas Cost Recovery Reconciliation;

Case No. U-13730	Gas General Rate Case;
Case No. U-13916	Gas Cost Recovery Plan;
Case No. U-13917-R	Power Supply Cost Recovery ("PSCR") Reconciliation;
Case No. U-14274-R	PSCR Reconciliation;
Case No. U-14347	Electric General Rate Case;
Case No. U-14403	Gas Cost Recovery Plan;
Case No. U-14403-R	Gas Cost Recovery Reconciliation;
Case No. U-14701-R	PSCR Reconciliation;
Case No. U-14716	Gas Cost Recovery Plan;
Case No. U-14716-R	Gas Cost Recovery Reconciliation;
Case No. U-15001-R	PSCR Reconciliation;
Case No. U-15415-R	PSCR Reconciliation;
Case No. U-15454	Gas Cost Recovery Plan;
Case No. U-15675-R	PSCR Reconciliation;
Case No. U-16045	PSCR Plan;
Case No. U-16045-R	PSCR Reconciliation;
Case No. U-16736	Energy Optimization Reconciliation;
Case No. U-16432	PSCR Plan;
Case No. U-16432-R	PSCR Reconciliation;
Case No. U-16890	PSCR Plan;
Case No. U-17197	Gas General Rate Case;
Case No. U-17281	Energy Optimization Reconciliation;
Case No. U-17601	Energy Optimization Reconciliation;
Case No. U-17688	Public Act 169 of 2014;
Case No. U-17735	Electric General Rate Case;

Case No. U-17990	Electric General Rate Case;
Case No. U-18322	Electric General Rate Case;
Case No. U-20134	Electric General Rate Case;
Case No. U-20102	Electric Tax Credit A;
Case No. U-20286	Electric Tax Credit B;
Case No. U-20563	Demand Response Reconciliation;
Case No. U-20889	Securitization of Karn Units 1 and 2;
Case No. U-20803	PSCR Reconciliation;
Case No. U-21308	Gas General Rate Case;
Case No. U-21049	PSCR Reconciliation;
Case No. U-21321	Energy Waste Reduction Plan;
Case No. U-21258	PSCR Reconciliation;
Case No. U-21424	PSCR Reconciliation;
Case No. U-21585	Electric General Rate Case; and
Case No. U-21859	Ex Parte Approval of Certain Amendments to Rate GPD.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present the Company's proposed rate design that will result in electric revenues sufficient to collect the total revenue requirement proposed by the Company in this case.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-16 (LMC-1)	Schedule F-2.0	Summary of Present and Proposed Revenues by Rate Schedule;
Exhibit A-16 (LMC-2)	Schedule F-2.1	Calculation of Rate Design Targets;
Exhibit A-16 (LMC-3)	Schedule F-3.0	Present and Proposed Revenue Detail;

Exhibit A-16 (LMC-4)	Schedule F-4.0	Comparison of Present and Proposed Monthly Bills;
Exhibit A-66 (LMC-5)		Demand Response (DR) Surcharge;
Exhibit A-67 (LMC-6)		Electric Rate Case (ERC) Deferral Surcharge;
Exhibit A-68 (LMC-7)		Investment Recovery Mechanism (IRM) Surcharge;
Confidential Exhibit A-69 (LMC-8)		Long-Term Industrial Load Retention Rate (LTILRR) Revenues; and
Confidential Exhibit A-70 (LMC-9)		Large Economic Development Rate (LEDR) Revenues.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. RATE DESIGN OVERVIEW

II. RATE DESIGN PROPOSALS

III. SURCHARGES

I. RATE DESIGN OVERVIEW

Q. Please describe the primary objectives of rate design.

A. Consistent with the rate designs approved in prior cases, I used the following four key objectives to inform my rate design in this case. My first objective was to adhere to the cost of service in accordance with the requirements set forth in MCL 460.11. I did deviate from the COSS in a couple of instances and will further elaborate on my rationale for doing so later. My second objective was to design rates that encourage the efficient use of the Company's electric system. This means setting rates that accurately reflect the type of cost (fixed versus variable) as well as the temporal nature of certain costs, such as the increased

cost of providing energy during peak seasons and times of day. My third objective was to design rates that promote a favorable business climate. My fourth objective was to design stable rates that provide the Company with a fair opportunity to collect its revenue requirement.

Q. Please describe the cost of service requirements set forth in MCL 460.11.

A. MCL 460.11 requires electric utilities to design rates that reflect the cost of providing service to each customer class. In other words, costs assigned to one class cannot be reassigned to another without cost justification. The intent of this being to prevent, or at the very least limit, interclass subsidies. However, this does not completely remove the utility's ability to maintain crossing-points between rates within a class and to make other adjustments to deviate from the COSS in some instances. I have identified these deviations as adjustments to the class COSS in Exhibit A-16 (LMC-2), Schedule F-2.1.

Q. Please describe your reasons for making these adjustments.

A. Consistent with prior electric rate cases, I am recommending six adjustments to the assignment of costs across the various rate classes and schedules as part of rate design. The first standard adjustment, shown on line 3 of Exhibit A-16 (LMC-2), Schedule F-2.1, reflects the difference between the market cost of production capacity collected from large standby customers taking service under Rate GSG-2 and the embedded cost of capacity allocated to them in the COSS. Two similar adjustments—the second and third—are made for both production energy and transmission costs, shown on lines 7 and 13, respectively. In total, these three adjustments suggest that large standby customers pay less under the market-based rate design structure for production and transmission standby service than they would under an embedded cost of service design.

The fourth standard adjustment, shown on line 18, is used to correct for an over allocation of substation costs to voltage levels 1 and 2 rates as part of the COSS. In the 2019 electric rate case, Case No. U-20134, it was brought to the Company's attention that it was inadvertently over allocating substation costs to the higher voltage level rates by excluding customer-owned substations from its COSS. To remedy this issue, the Company agreed to reassign the portion of substation costs by allocating those costs to customers who owned their substation in the COSS as part of rate design. The easiest way to accomplish this was to allocate the substation ownership credits across the rate classes based on the distribution allocators developed in the COSS.

The fifth adjustment, shown on line 19, reflects the life line credits (senior citizen and low-income) that have traditionally been supported by all customer classes. Unlike the other approved adjustments, however, the life line adjustment is not cost justifiable. Instead, it is based on the Commission's authority to approve special senior citizen and low-income rates granted under MCL 460.11.

The sixth adjustment, shown on line 2, reflects the removal of the Demand Response ("DR") revenue requirement calculated by Company witness Patrick D. Daly in Exhibit A-83 (PDD-59) and allocated to each rate schedule by Company witness Emily A. Davis in Exhibit A-89 (EAD-5), from base rates. The Order in Case No. U-21585 approved the Company's proposal to consolidate the DR program costs, customer credits, financial incentives, and regulatory balances into an all-encompassing surcharge. This adjustment is described further by Company witness Alex M. Gast.

Q. Please explain your approach in designing rates to collect the Company's production costs.

A. Production is comprised of both fixed and variable costs, which are separated in the COSS between capacity and energy costs. Production capacity represents the cost of a generating plant and having it stand ready to serve customer demand over an extended period of time (annually) or at a certain hour (peak). Conversely, production energy represents the cost of running these plants and is usually attributed to fuel expenses. Traditionally, the Company has used a combination of historical prices based on the Midcontinent Independent System Operator, Inc. ("MISO") market to estimate the energy price spread of providing service during different time periods.

Q. Are you recommending any changes to the methodology used to calculate the production energy price spreads as part of the rate design?

A. No. Consistent with the method used in the prior electric rate case, Case No. U-21585, the Company is using the weighted average hourly Locational Marginal Pricing ("LMP") to calculate the energy charge spreads for the various Time-of-Use ("TOU") rates. This weighting of hourly LMP values based on the corresponding hourly energy use better reflects the value of energy in each time period.

Q. Please describe the calculation of the LTILRR revenues shown in your Confidential Exhibit A-69 (LMC-8).

A. The first page of Confidential Exhibit A-69 (LMC-8) contains the forecasted test year billing determinants and monthly charges based on the approved LTILRR tariff and customer contract. The second page of Confidential Exhibit A-69 (LMC-8) calculates the test year miscellaneous revenues, provided to Company witness Eugène M. Breuring,

based on the information from the first page and the forecasted production and transmission costs sponsored by Company witness Megan L. Metz.

Q. What happens if actual LTILRR electric sales are less than the level forecasted by the Company in this case?

A. Any changes in the electric sales and power supply costs associated with the LTILRR are included in the Company's annual PSCR plans and reconciliations. For example, if the actual LTILRR electric sales are lower than the levels forecasted in this case, then the Company would include the lower power supply miscellaneous revenue as part of the LTILRR payment in its PSCR reconciliation. Similarly, a higher sales level would result in a higher payment in the PSCR reconciliation.

Q. Is the Company recommending any changes to the LTILRR in this case?

A. No, it is not.

Q. Please describe the calculation of the LEDR revenues shown in your Confidential Exhibit A-70 (LMC-9).

A. In Case No. U-21160, the MPSC approved the LEDR tariff and inclusion of the related LEDR revenues in general rate cases as miscellaneous revenue. Confidential Exhibit A-70 (LMC-9) contains the forecasted test year billing determinants and monthly charges based on the approved LEDR tariff and forecasted customer usage during the test year. The calculated LEDR revenues are picked up by Company witness Breuring as part of total miscellaneous revenue in Exhibit A-15 (EMB-3), Schedule E-2.

Q. Is the Company proposing any changes to LEDR in this case?

A. Yes. The changes to LEDR are discussed below.

II. RATE DESIGN PROPOSALS

A. Residential

Q. Please explain your approach in designing the Company's residential customer class rates.

A. The Company is recommending the Commission maintain the currently approved residential rate design structure. My overall objective in designing the residential rates was to continue providing a sense of stability for this class by maintaining the existing rate structures for each option—i.e. Residential Summer On-Peak Basic Rate ("RSP"), Residential Smart Hours Rate ("RSH"), Residential Nighttime Savers Rate ("RPM"), and Residential Service Secondary Non-Transmitting Meter Rate ("RSM"). There are no changes proposed to the structure or type of charges. Also, the collection of charges within the available rate options were evaluated based on how each fit individually and collectively within the class. For example, the summer on-peak charges assessed in all three residential TOU options were set equal since each covered the same period and are intended to inform customers about the cost of providing power during that period.

Q. What is the monthly residential bill impact under your proposed rate design?

A. The average monthly residential customer bill is projected to increase 11% from approximately $132 per month to $146 per month. The monthly customer typical bill impacts for each rate schedule are also shown in Exhibit A-16 (LMC-4), Schedule F-4.0.

Q. How does the residential monthly bill under your proposed rate design compare with the national average bill projected by the Energy Information Administration ("EIA")?

A. The national average residential electric bill from the EIA is projected to be $154 per month in 2026, which is approximately $8 more than the $146 per month projected for the Company's customers. The Company also offers customers various payment plans and ways to reduce their energy bills through its residential assistance, energy efficiency, and DR programs. In addition, customers interested in proactively managing their energy bills can use many of the programs and digital tools the Company provides; including the online energy dashboard and billing detail to understand how energy is used throughout the day, tips for reducing energy waste, bill forecast trends, and the rate advisor tool to identify actions that can be taken to reduce their bills.

Q. Is the Company proposing any change to the Residential Smart Meter Opt Out Fees?

A. Yes. As discussed in the testimony of Company witness Michael P. Kelly, the Order in Case No. U-21585 directed the Company to re-evaluate its advanced metering infrastructure opt-out charges and include the results in its next case. As such, Company witness Kelly is proposing to update the Residential Smart Meter Opt-Out fee. That update is reflected in Exhibit A-16 (LMC-3), Schedule F-3.0, page 4 of 23, on line 14.

B. <u>Secondary</u>

Q. Is the Company proposing any changes to the Secondary rate structure?

A. No, the Company is proposing to maintain its current rate structure for secondary customers.

C. Primary

Q. Is the Company proposing any changes to the Primary rate structure?

A. The Company is not proposing any changes any changes to the rate structure for Primary Rates GP, GPD, GPTU, or EIP.

Q. Is the Company proposing any changes to LEDR?

A. Yes. First, the Company is proposing to update the production capacity charge based on the latest forecast of MISO Cost of New Entry ("CONE"). Second, the Company is proposing to include a facilities allowance in LEDR. Lastly, the Company is proposing to include a Power Factor adjustment as part of LEDR.

Q. Please describe the Company's proposal to include a facilities allowance with the LEDR.

A. The LEDR was first established by the Commission in Case No. U-21160 and implemented in December 2021. Since its implementation, potential customers have inquired about the availability of a facilities allowance such as that offered under DTE Electric Company's Rate D13. To better align with other cost-based large customer rate options in Michigan, the Company is proposing to add language to the tariff that would clarify a facilities allowance would be applicable to customers on the rate.

Q. Please describe the Company's proposed method for calculating the facilities allowance for customers.

A. The Company is proposing to calculate the facilities allowance for each prospective customer based on the net present value of margin – defined as the non-energy related costs – based on their expected load over five years of the contract term.

Q. Does this proposal address the Commission's recommendation in the Case No. U-21585 Order?

A. Yes. The Order in Case No. U-21585 stated "in its next electric rate case, if the company believes it beneficial to provide a facilities allowance for Rate LED, Consumers should propose a facilities allowance that includes only distribution and system contribution revenues, not power supply revenues, and that is based on a limited term". The Company's proposal is to base the allowance on the non-energy related costs and limit the margin to five years.

Q. Why does the Company believe five years is an appropriate length of time to use in the calculation of the allowance?

A. Five years corresponds to the standard Contribution in Aid of Constructure Allowance offered to standard primary customers.

Q. Is the Company proposing any other changes to LEDR?

A. Yes, the Company is proposing to add an adjustment for Power Factor to LEDR. Consumers Energy must adhere to Power Factor standards for all customers and LEDR customers are no exception.

Q. What type of adjustment for Power Factor is the Company proposing?

A. The Company is proposing to mirror the design of the recently approved Power Factor adjustment for Rates GP, GPD, GPTU, and EIP. However, the Company is proposing to assess penalties for Power Factor between 0.700 and 0.909.

Q. Why is the Company proposing a higher penalty band for LEDR?

A. Consumers Energy must adhere to specific Power Factor requirements outlined in our Distribution-Transmission Interconnection Agreement ("DTIA") with Michigan Electric

Transmission Company ("METC"), filed at the Federal Energy Regulatory Commission ("FERC"). These requirements state that at system load levels above 90% of peak, the Company must maintain an average Power Factor of 0.98 or better across all interconnection points with METC. Historically, this has not been an issue but customers on LEDR will have larger loads than our current customer base and could have a greater impact on the Company's total system Power Factor. Thus, the Company is proposing that these customers be held to a higher Power Factor standard.

D. Lighting

Q. Is the Company proposing any change to the streetlighting rate structures?

A. No, the Company is proposing to maintain the current rate structure for the streetlighting rates.

E. Self-Generation

Q. Is the Company proposing any change to the Self-Generation rate structure?

A. No, the Company is proposing to maintain the current rate structure for Rate GSG-2.

F. Power Factor

Q. Is the Company proposing any change to the existing Power Factor credit and penalty structure?

A. Aside from the proposal above to add a Power Factor adjustment to LEDR, the Company is not proposing any further changes to Power Factor. The Commission approved changes to the application of Power Factor in Case No. U-21585. The Company has not yet implemented those changes. Once those changes are implemented, the Company will evaluate their effectiveness and determine if additional changes are necessary.

III. SURCHARGES

Q. Please describe the method used to develop the DR surcharge proposed by Company witness Gast.

A. As discussed by Company witness Gast, the Company is proposing to collect the revenue requirement for the DR Program inclusive of all DR related capital, O&M costs, and rate credits in an all-encompassing surcharge. The DR program costs of $43,572,000 is calculated by Company witness Daly in Exhibit A-83 (PDD-59) as a revenue requirement and allocated to the various rates in Exhibit A-89 (EAD-5). The removal of the DR revenue requirement from base rates is shown in Exhibit A-16 (LMC-2), Schedule F-2.1, line 2, and the corresponding DR surcharge to collect the test year DR revenue requirement and customer credits is shown on line 23 in the same exhibit.

Q. Please describe the method used to design the ERC Deferral surcharge in this case.

A. As discussed by Company witness Daly, the Company is proposing an ERC Deferral surcharge to recover $24,327,000 of deferred distribution investments. Similar to the existing surcharge, the deferred costs were allocated to the various rates in Exhibit A-89 (EAD-5) and divided by the test year sales to calculate the surcharge.

Q. Describe the IRM proposed by the Company.

A. The proposed IRM would authorize the Company to collect additional revenues associated with incremental distribution reliability spending beginning May 1, 2026 through April 30, 2028, with a distinct revenue amount to be collected in each 12-month period, as discussed in the testimony of Company witnesses Heidi J. Myers and Kelly.

Q. Please describe Exhibit A-68 (LMC-7).

A. Exhibit A-68 (LMC-7) is an illustrative calculation of the proposed IRM surcharge. It shows how the Company proposes to collect the revenue requirements associated with the IRM. The revenue requirements for each class are based on the cost allocation of the revenue requirements in Exhibit A-89 EAD-5). The rate design for the various voltage levels for Rates GP, GPD, EIP, and GPTU are consistent with the rate differentials used in the Company's rate design. The surcharge is based on test year sales and would apply to both Full Service and Retail Open Access customers. With approval of the Commission, these rates would be effective for service rendered on and after May 1, 2026 and service on and after May 1, 2027. The IRM surcharges would continue until rates were modified in the Company's next electric case.

Q. How does the Company propose to reconcile the IRM?

A. As discussed in the testimony of Company witness Myers, the reconciliation of the IRM would be handled in a separate contested proceeding. The Company proposes to reconcile the IRM capital spend on an annual basis. The reconciliation would compare the Company's annual IRM revenue requirement based on the actual incremental investments for that 12-month period against the associated revenue requirement collected from customers by class for that year through the IRM surcharge. If, for example, the actual IRM revenue requirement fell short of the Commission-approved amount collected through the surcharge, then the Company would refund customers the difference.

Q. Would the Company be allowed to increase the surcharges over the amount the Commission approved in a final order in this case?

A. No. The Company would only be authorized to implement the surcharges approved by the Commission in this proceeding. However, the Company would implement reductions as ordered by the Commission to modify the surcharge if the amount of the investment was less than the total incremental investment proposed spend amount.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

LAURA M. CONNOLLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Laura M. Connolly, and my business address is One Energy Plaza, Jackson, MI 49201.

Q. Are you the same Laura M. Connolly who previously submitted testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Kevin S. Krause; Association of Businesses Advocating Tariff Equity ("ABATE") witness James R. Dauphinais; Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (collectively "MNSC") witness Caroline Palmer; Michigan Environmental Council and Natural Resources Defense Council (collectively "MEC-NRDC") witness Scott Reeves; Solar Technology LLC ("SLT") witness Michael P. Gorman; and Walmart Inc. ("Walmart") witness Matthew T. Lyon.

Q. Are you sponsoring any exhibits?

A. No.

Q. How is your rebuttal testimony organized?

A. My rebuttal testimony is organized by the following topics:

I. Power Factor

II. Data Centers

III. Large Economic Development Rate

IV. EV Rates

V. Heat Pump Rates

I. Power Factor

Q. Both ABATE witness Dauphinais, at pages 24 through 26, and SLT witness Gorman, at pages 2 through 4, of their direct testimony agree with Consumers Energy Company's ("Consumers Energy" or the "Company") proposal to add a power factor adjustment to the Large Economic Development Rate ("LEDR") but recommend it be equivalent to the power factor requirements approved for other primary rates. How do you respond?

A. After further review, the Company agrees with ABATE witness Dauphinais and SLT witness Gorman on this issue. There remains concern that an extremely large customer could influence the overall power factor. Power factor correction strategies must be tailored to the scale and configuration of the customer's electrical service. Large customers, due to their substantial power demands and direct interconnection to the transmission system, present unique challenges. However, the Company recognizes this discussion may be premature and will address those concerns in a future filing.

II. Data Centers

Q. At page 22 of her direct testimony, MNSC witness Palmer references an August 1, 2025 news release announcing the Company had reached an agreement with a new data center. She states that given this announcement, the Commission and the Company should prepare now for data center cost allocation. How do you respond?

A. While the Company did announce an agreement with a new data center, the announcement was based on a Letter Agreement. The Letter Agreement addressed internal system studies necessary to serve the customer, however, it did not outline a load ramp schedule. Absent

a signed rate contract for service to be provided in the test year, it would be premature to start making decisions about cost allocation in the instant case.

Q. What does MNSC witness Palmer recommend regarding potential data center load and cost allocation?

A. At page 23 of her direct testimony, MNSC witness Palmer recommends that the Commission order the Company to demonstrate in its next rate case that its proposed cost allocation methods satisfy the legislative requirement that residential customers will not subsidize the costs incurred to provide electric service to a data center.

Q. How do you respond?

A. This is an unnecessary requirement as the Company must adhere to the approved cost allocation principles which requires that electric rates are equal to the cost of providing service to each customer class , as set forth in MCL 460.11.

Q. What does MNSC witness Palmer recommend regarding data centers and Integrated Resource Plan ("IRP") modeling?

A. At page 24 of her direct testimony, MNSC witness Palmer recommends that the Commission order the Company to conduct sensitivity modeling runs in its next IRP with and without data center load of magnitude that reasonably reflects the Company's expected data center load at the time.

Q. How do you respond?

A. This is an unnecessary requirement as the Company already includes various sensitivities in the IRP, which includes scenarios based on the probability of new load coming onto the system.

III. Large Economic Development Rate

Q. At page 27 of her direct testimony, MNSC witness Palmer expresses concern that LEDR customers may not be paying the marginal cost associated with higher demand on the rest of the shared distribution system. Was LEDR set based on marginal distribution costs?

A. No. As established in Case No. U-21160, LEDR's capacity charges are set based on the marginal cost of capacity. However, the distribution charges for LEDR are the same as the distribution charges set for the Company's Large General Service Primary Demand Rate ("GPD"). In addition, LEDR customers pay for investments made by the Company for incremental distribution facilities required to serve them through a levelized incremental distribution charge. Therefore, LEDR customers are paying the same distribution rates as other customers paying embedded cost rates, in addition to the incremental costs associated with their distribution facilities. Other similarly situated customers are afforded a Contribution In Aid of Construction ("CIAC") allowance to cover some or all of the incremental costs of the distribution facilities to serve them. MNSC witness Palmer's notion that the Company must demonstrate that an LEDR customer will pay all its marginal distribution costs in order to gain approval of a facilities allowance is flawed and not consistent with the methodology approved by the Commission in approving the LEDR. As stated in my direct testimony, the Company's design of the proposed facilities allowance is in accordance with the Order in Case No. U-21585 and should be approved in this filing.

Q. MNSC witness Palmer states, at page 29 of her direct testimony, that if approved, the facilities allowance should not be applied retroactively to current LEDR customers as the Company has already succeeded in attracting these customers. How do you respond?

A. While it is true that customers have already signed to take service under LEDR, part of the negotiation with these customers was around potential for a future facilities allowance. Their contracts contained language expressing the Company's intention to file a request to amend this rate to allow LEDR customers to qualify for a CIAC credit. These customers considered this language and potential for an allowance as part of their decision to locate in the Company's service territory. Should the Commission approve the facilities allowance, it should be applied to customers with express language in their contract around the potential for an allowance.

Q. At page 30 of her direct testimony, MNSC witness Palmer states that it does not appear that the Company intends to true up the facilities allowance if the Company initially overestimated a customer's expected annual revenues. She recommends the Company reconcile any overestimated revenue from the provided facilities allowance and recalculate the customer's incremental distribution charges accordingly. How do you respond?

A. The LEDR tariff states that this charge may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities. As part of this adjustment, the Company intends to reconcile any differences in actual collections to proposed collections and would include the facilities allowance in those calculations.

Q. At page 31 of her direct testimony, MNSC witness Palmer also recommends that the Company raise the system contribution charge assessed to LEDR customers. How do you respond?

A. The Company recommends the Commission reject MNSC witness Palmer's proposal. MNSC witness Palmer states that the Company did not base the charge on any cost basis yet and does not provide an alternative solution other than to increase it. The system contribution charge was approved as part of the Order in Case No. U-21160. Customer contracts state that this charge is set for the term of the contract. If the Commission were to order the Company to change the system contribution charge, it should be updated consistent with the methodology used to develop the charge in Case No. U-21160.

Q. At page 33 of her direct testimony, MNSC witness Palmer recommends the LEDR "discount period" should be shortened from 15 to 20 years to a maximum of 7 years. How do you respond?

A. MNSC witness Palmer's recommendation should be rejected. There is no discount associated with LEDR; it is based on cost of service. The Order in Case No. U-21160 states "The Commission further finds that the proposed LEDR complies with the Michigan law, and is reasonable and in the public interest." Characterizing LEDR as a discounted rate implies that the Commission approved a rate that violates Michigan law. This mischaracterization undermines the integrity of the Commission's review and approval process in Case No. U-21160.

Q What impact could shortening the contract length have on the rate?

A. A shortened contract length could result in potential stranded assets should a customer decide to cease taking service from the Company at the end of their contract term. LEDR

is available to customers using 35 MW or greater, which is a significant amount of load. This could come with significant investment costs in infrastructure to serve that load. That infrastructure could be stranded should a customer cease taking service from the Company just seven years later.

IV. Electric Vehicle Rates

Q. At page 4 of his direct testimony, Staff witness Krause proposes that the Company introduce a new tariff for fast charging in its next rate case based on available fast charging data and that this tariff be based on cost of service. How do you respond?

A. The Company has limited data with which to develop a cost of service to support a fast charging rate. To try to do so at this time would be premature.

Q. Why is it premature?

A. Currently, the Company is only able to identify fast charging customers which were rebated under the PowerMIDrive program. The annual data from the 2025 Transportation Electrification Program ("TEP") report indicated that this is 84 Direct Current Fast Charging ("DCFC") customers. Of those 84 customers, the Company has not analyzed how many have a full years' worth of data, much less the standard three years of data that is typically used to develop a cost-of-service study ("COSS"). In addition, this does not account for a potentially sizable number of DCFC customers which are not separately metered but rather aggregated in a customer's total load.

Q. Has the Commission addressed this issue in other proceedings?

A. Yes, in Case No. U-21297, DTE Electric Company ("DTE Electric") was ordered to "conduct a separate COSS to allocate appropriate costs to fast charging and design and propose rates for this specific class of customer in its next rate case" (page 342). DTE

Electric did this in its next case, Case No. U-21534, utilizing data from 21 chargers of approximately 68 known DCFC customers to develop an alternative COSS and rate design. DTE Electric witness Aaron Willis recommended that their proposal should be used as a starting point for discussion only and not as a rate to be implemented given the data constraints and generally small customer set. The Commission agreed, stating in its order that "there is not currently enough historical data to analyze given the small number of EV DCFC and finds it premature to implement the company's proposed alternative COSS and rate design at this time." The Company's DCFC data is similarly constrained, and as such, the Company should not be directed to develop a COSS and rate design in its next case.

Q. Starting January 1, 2021, the Company closed General Service Primary Rate ("Rate GP") to new business other than for service to DCFC stations. On page 4 of his direct testimony, Staff witness Krause recommends that the Commission close Rate GP to new fast charging stations and move existing fast charging stations to the to-be-created DCFC tariff. How do you respond?

A. Mr. Krause's proposal goes along with his proposal above to develop a DCFC COSS and rate design for these customers to move to. Given the discussion above, this proposal should be rejected.

Q. Walmart witness Lyon also proposed the Company develop an electric vehicle ("EV") charging specific rate for third-party owned public EV DCFC stations. How do you respond?

A. For the same reasons addressed above, the Company recommends this proposal be rejected until the Company has more data to base a rate on.

V. Heat Pump Rate

Q. At page 10 of his direct testimony, MEC-NRDC witness Reeves proposes that the Commission requires the Company to develop and propose an electric heat or heat pump rate design. How do you respond?

A. While not addressing the policy concerns of MEC-NRDC witness Reeves testimony, the Company does not oppose exploring an electric heat/heat pump rate design. The Company does not agree with the prescriptive approach as MEC-NRDC witness Reeves has outlined.

Q. Please explain.

A. MEC-NRDC witness Reeves suggests the Company be required to work with the Commission and other stakeholders in the development of the rate and be required to present the proposed rate for approval within 12 months of the order resolving this rate case. MEC-NRDC witness Reeves further outlines several considerations for designing the rate. The Company would prefer to address this issue in the context of a general rate case and as such imposing a 12-month timeline may not be practical in relation to future rate case filings. The Company can explore developing an electric heat pump rate in its next general electric rate case. The general rate case process would allow all interested intervenors to comment and critique the Company's proposal. The Company would endeavor to hold a stakeholder session in advance of that filing to solicit ideas of interested parties. As part of the contested case process, all parties would have the opportunity to opine on the proposed electric heat/heat pump rate.

Q. Does this conclude your rebuttal testimony?

A. Yes.

THE COURT: Mr. Bzdok, are you going first?

MR. BZDOK: Yes, Your Honor, thank you.

THE COURT: Thank you.

CROSS-EXAMINATION

BY MR. BZDOK:

Q. Good morning, Ms. Connolly.

A. Good morning.

Q. I want to talk to you about two topics today. One is a topic, I guess both are topics we've discussed before. One is the LED, large economic development rate. LED rate or LEDR, and the other is data centers. Let's start on your direct testimony at page 12.

A. Okay.

Q. So just -- just some jumping off points here. In your direct on page 12, you are proposing or sponsoring a proposal to include a facility's allowance in -- within the LED rate, is that right?

A. Correct.

Q. And that proposal is reflected in Ms. Witness Gray's proposed tariff sheets, is that right? Exhibit A-16, Schedule F, five?

A. Yes, that's correct.

Q. Do you have that available through the SharePoint or otherwise?

A. I can find that through the SharePoint.

Q. Great. Once you're there, I have a page number for you.

A. I have it open.
Q. Page 65, which just for the record, is an amendment to sheet number D-78.30.
A. I'm there.
Q. Great, so at the top of page 65 or sheet D-78.30, there is in track changes the -- the words a facilities allowance. Correct?
A. Correct.
Q. Is this the only tariff change associated with this proposal?
A. Yes.
Q. Okay. Just for foundational purposes, I believe in past cases you have served, among other roles as a rate design witness, is that right?
A. Yes.
Q. You have also served as a cost of service witness, is that right?
A. Yes.
Q. You have also sponsored tariff sheets similar to these, with you being the sponsoring witness, is that right?
A. Yes.
Q. Okay. I also want -- our other jumping off point is going to be your rebuttal testimony, if you have that available.
A. Yeah.
Q. So in your rebuttal testimony starting at page 4, you are responding to MEC witness -- oh, let me -- let me wait for

you bit.
A. I'm there.
Q. Just high level you're responding on those pages to MEC witness Caroline Palmers testimony, which is objecting to or opposing the addition of a facility's allowance to the LED rate, is that right?
A. Correct.
Q. And then also in your rebuttal on page 6, you are responding to witness Palmer's testimony recommending that the -- the commission increase the system contribution charge associated with the LED rate and reduce the maximum contract term available under the LED rate, is that fair?
A. Yes, that's correct.
Q. Okay. And those are the things I want to talk about today as for the LED portion of this discussion. So looking still at Exhibit A-16, Schedule F-5, the terms for the LED rate including some updates, the terms for the LED rate up here on that exhibit beginning on page 64 sheet 7-D, is that right?
A. Yes.
Q. I -- I want to talk. Just -- just lay some markers down regarding the components of the LED rate which I believe you -- you also talk about some of the components of the LED rate in your rebuttal testimony, is that right?
A. Yes.
Q. So, for example on page 4 of your rebuttal, you talked

about the distribution charges for LEDR, lines seven through nine, right?

A. Yes, that's correct.

Q. And if I travel over to Exhibit A-16, schedule F-5, page 65, there are distribution charges present there. Is that correct?

A. Yes.

Q. And those distribution charges, including the updates of the distribution charges, are -- are -- they are the same, I believe as the distribution charge for the GPD rate, at I believe it's voltage level one. Does that sound right? I can give you a page reference.

A. Yes. These match the rate GPD distribution or demand charges for each voltage level.

Q. And by demand charges, you're referring to distribution demand charges?

A. Correct.

Q. Okay. Do you have a page reference you're looking at for that for GPD?

A. I was looking at the -- the LED tariff page that you provided me, just clarifying you mentioned voltage level one, but each of the voltage levels on this tariff for the LED rate correspond to the distribution charges for rate GPD.

Q. Okay. The distribution for -- for the LED rate, the distribution charges that are part of the LED rate

represent the GPD customer share, if you will, of embedded distribution system costs, is that correct?

A. The distribution charges represent more than just rate GPD, our rates GPTU, EIP, and GPD all pay the same distribution charges along with rate LED.

Q. And what those customer groups, or customer classes, or tariff classes have in common is that these -- these are the big primary customers, is that right?

A. That's correct.

Q. And with that qualification, which I appreciate, or that clarification, the -- would you agree with me that the rate LED distribution charges are -- are -- are -- are representative of a share of embedded distribution system costs?

A. Yes.

Q. And I don't know if I got this, so I'm going to ask it again just in case. The -- the distribution charges for rate LED may be modified from time to time in rate cases under the tariff, is that right?

A. That's correct.

Q. They're not fixed for the life of the LED contract, right?

A. Correct. The distribution charges for rate LED will change in general rate cases as our rate GPD and other large primary rates change.

Q. Thank you. Production charges for LED rate are set forth in Exhibit A-16, Schedule F-5, page 65 -- 64, excuse me.

Is that right?
A. Yes.
Q. And production charges, they are stated in dollars per kilowatt for customer voltage levels one, two and three. Is that right?
A. Yes.
Q. And then there is a statement below that that says effective for contracts stated on and after June 7, 2024, the monthly production charge is the cost of new entry for MISO's local resource zone seven or CONE as of the time of contract execution, correct?
A. Yes.
Q. So, am I understanding correctly that what this means is that the updates on production charges for LED rate only apply to contracts for LED service that were entered into before this June 2024 date?
A. Did you say that it entered on before this date?
Q. I'm trying to understand the significance. Maybe I'll try to ask it a different way. I'm trying to understand the significance of the first sentence below those production charge figures, really the first two sentences that you referred to CONE for contracts dated on and after June 7, 2024, and also refer to the monthly production charge being fixed for the contract term at the rate in effect at the time of contract execution. So -- so I guess my question is are those -- how did those sentences relate if

they do, to the -- the numbers that are immediately above them under projection production charge?

A. For a contract date on and after June 7, 2024, the customer is going to pay the production charge at 100% of CONE contracts that were executed prior to the June 7, 2024 date paid a different percentage of CONE as was approved in the initial filing for the large economic development rate. So the sentence is -- is meant to clarify or make clear what costs of new entry these customers are paying when they enter into this rate.

Q. Okay. A second -- so -- so I appreciate that. And I want to gather up one other piece of that, if I could. What I'm seeing in the -- in the fact that there are certain numbers in track changes suggests to me that for contracts entered before June 7, 2024, the production charge will -- will change from time to time. Is that right?

A. No, that's not correct. When a customer signs a contract for the rate LED, their production charges locked for the term of the contract. This -- these two sentences that we're looking at are meant to clarify the difference in the timing of when customers sign a contract.

Q. Okay. So is what you're saying that if a customer -- so are these numbers representative then of CONE at this time?

A. The numbers in blue, so the new numbers that were presenting in this case, would be a 100% of CONE as of the

forecast that we use when we put together this case, so the latest cone information.

Q. So if a customer signs a contract during the 2026 projected test year. They'll pay these numbers as reflected 100% of CONE at that time?

A. They'll pay that rate that are approved on the tariff at the time they sign.

Q. Okay. And once they sign, the -- the amount that they're paying will remain fixed for the duration of their contract or it's 15 years, 20 years, or some other figure?

A. That's correct.

Q. So as MISO resets come from time to time, these -- under these contracts, LED customers who have signed a contract will not have their production charges increased commensurate with the increases in MISO CONE values if -- if there are increases, fair?

A. That is correct.

Q. As time goes on over a 15 or 20 year term, assuming the cost, as this is a hypothetical question assuming the cost of CONE increases over time, there will be a difference or a delta between what the customer's paying and what the actual CONE value is that -- that will grow over time. Fair?

A. Assuming that CONE is growing. Yes, that's correct.

Q. The reason that the rationale for the use of CONE for the production charge, is that it represents an incremental

cost of capacity, is that right?
A. That's correct.
Q. To the extent that a contract has a fixed production charge at CONE at the time of execution, and CONE increases in 10, 15, 20 years going to forward. The difference between what the customer is paying and the actual incremental cost of capacity would also increase, hypothetically speaking. Right?
A. Can you restate the question?
Q. Sure. So I'm sort of closing the loop on the -- the -- the earlier pieces, or at least I'm attempting -- I'm attempting to bring them together. So customer signs a contract for 20 years, that's allowed right now, right?
A. Right.
Q. And at the time the customer signs their production charges, locked at CONE in year one, correct?
A. Correct. That would be the cost of new entry at the time they sign. So if we are going to secure capacity for them, they pay -- they are locked into that cost of new entry, the 100% of CONE production charge for the term of the contract.
Q. And the rationale for that is that that represents the incremental cost of capacity at the time of execution, right?
A. Yes. That would represent the cost that we have to go

incur to serve that customer at that time.
Q. As a practical matter Consumers is not buying capacity for 15 or 20 years at the cost of CONE to serve that customer, right?
A. I don't know how we buy capacity.
Q. Let me ask it this way, then. Are you aware of any facts that would suggest, just from your dealings with the LED rate and the changes to the LED rate, are you aware of any facts that suggest that Consumers has for any LED customer or customers secured 15 or 20 year capacity contracts at present CONE?
A. I'm not aware of what capacity contracts we've entered into on behalf of any large economic development customers.
Q. Okay. Give me a second. Bear with me. Just a second. I'm grabbing another document. And would you agree that Consumers embedded cost of capacity is greater or higher than an a 100% CONE?
A. My understanding is that it is, yes.
Q. I want to toggle the GPD pair of sheets in A-16, Schedule F-5, with the LED sheets. The GPD sheets specify -- so I'm looking for example at -- in that exhibit, I'm looking at page 40 -- 48 in A-16, Schedule F-5.
A. Okay.
Q. And if I'm comparing -- so if I'm looking on -- on that page for GPD. There is a heading power supply charges,

and then there is a subheading charges for customer voltage level three. Do you see that?

A. Yes.

Q. And there are demand charges stated as non capacity, capacity, and total for two different seasons, is that right?

A. Correct.

Q. And that is true then also of the voltage levels two and voltage level one on the next page, correct?

A. Yes.

Q. What do -- what do these charges represent?

A. These would represent the embedded capacity cost for rate GPD for the peak billing period.

Q. Okay. So if I was trying to make an apple to apples comparison, apples to apples is sort of a loaded term. So if I'm trying to compare what is being charged for fixed production related costs, let's say. For GPD and LED, I would be looking at the total demand charges for the two seasons in GPD compared to the production charges for LED rate, if I just wanted to look at what are the two types of customers being charged for fixed production?

A. That's correct.

Q. Okay. Thank you. And then, of course, I can relate the voltage levels, because these are all broken out by voltage levels for both types of customers. Correct?

A. Yes.

Q. Okay. So just as for an example, so that the record is super crystal clear, if I'm looking at voltage level three on page 48 of A-16, Schedule A-5, I can compare total demand charges for a GPD customers that are $15 or $17.01 per kilowatt, depending on the season with demand with production charges, or an LED customer at voltage level three of $11.61 per kilowatt, right?

A. Yes, that's correct.

Q. Okay. And that -- that difference between the $11 and change for the LED customer voltage levels and the higher amounts for the GPD customer demand charges reflects the difference between the cost -- the marginal cost of capacity and the cost of embedded capacity?

A. That's correct.

Q. And would you agree high level and generally that it's been the experience that the embedded cost of Consumer's capacity rises over time?

A. Yes.

Q. So going forward in a 15 or 20 year contract, the difference between the cost of capacity for an LED customer and the cost of capacity for a GPD customer can be expected to grow?

A. That is correct.

Q. LES customers can, as some other customers can, as well. LED customers can elect interruptible service, is that right?

A. Yes.
Q. Okay. If an LED customer elects interruptible service, then these production charges under the LED rate are discounted by the portion of load that the LED customer elects to be interrupted, is that right?
A. Yes.
Q. Okay. So it at -- at 50% interruptible, these charges 11.27, 11.43, and 11.61 per kilowatt would be cut in half for the LED customer. Is that right?
A. That's correct.
Q. And at a 100% interruptible these charges would be zero, is that right?
A. That's correct.
Q. Okay. Is there other LED charges that are also discounted, or reduced, or eliminated through the election of interruptible service? I'm wondering about system contribution charge.
A. No. The interruptible provision on the LED service as an offset to the production charge for the amount that is elected as interruptible. It does not change any other rates.
Q. Okay. Thank you. The system contribution charge, which we just mentioned appears immediately above the production charge under monthly rate, is that right.
A. Yes.
Q. And it's 0.000284 dollars per kilowatt hour for all

kilowatt hours, is that right?
A. Yes.
Q. And that represents that -- that figure represents about th -- that's a little less under 3 hundreds of a cent for kilowatt hour, right?
A. Yes.
Q. And that figure represents 1% of what the company's embedded cost of generation was in 2021 when the LED rate was originally approved, is that right?
A. That's correct.
Q. And this is the -- sorry did you have some else? I thought maybe you said something else. I might have heard it a different voice. I just didn't want to talk if you were not finished answering. Since being said in 2021 and the ex parte approval, the system contribution charges never increased, is that right?
A. That's correct.
Q. Consumers embedded cost of capacity has increased, right?
A. Yes.
Q. The system contribution charge is also fixed for the life of the 15 or 20 year contract, is that right?
A. That's correct.
Q. Okay. Let's look at the transmission charge. So -- so the transmission charge appears immediately below the production chart, is that right?
A. Yes.

Q. And the transmission charge for the different voltage levels ranges from $1.59 per kilowatt to a $1.64 per kilowatt, is that right?
A. Yes.
Q. The transmission charge is also meant to be an -- an incremental or marginal to cover an incremental or marginal associated with these customers, is that right?
A. That's correct.
Q. If I look at the GPD rate, the tariff pages, starting on page 48 of that same exhibit. I see transmission charge non capacity figures for the two seasons, right? Of $9.45 per kilowatt and $8.80 per kilowatt, is that right?
A. I'm just at the tariff now, can you repeat the -- the numbers that you're referencing?
Q. I thought that -- maybe I moved too fast on that, sorry about that. So -- so my question for you is this, which is similar to what we did -- the one we did with the production charges. I'm trying to figure out which charges in the GPD rates correspond to the transmission charges for the LED rate. And so I -- I'm looking at page 48 of the same exhibit, A-16, Schedule F-5, where there are transmission charges stated non capacity for voltage level three of $9.45 per kilowatt for the summer season and $8.80 per kilowatt for the -- the -- the rest of the months, do you see that?
A. Yes.

Q. Are those the -- if I'm comparing the transmission charges between LED rate and a GPD rate, voltage level three, I guess LED rate voltage level three and GPD rate voltage level three, is that the right comparison? The $1.64 for LED rate, and $9.45 and $8.80 depending on the season for GPD rate voltage level three?

A. Yes. Those comparable transmission charges for voltage level three.

Q. And -- and they could do the same comparison on the next page using the same categories to compare the other voltage levels between GPD and LED, is that right?

A. Yes.

Q. Transmission charges are not fixed for the life of the LED contract, right?

A. That's correct.

Q. They are adjusted annually based on a determination in the PSCR of what the incremental or marginal transmission cost for the particular LED customer is?

A. That's correct.

Q. I'd like to look at one of your exhibits now which is Exhibit A-16, Schedule F, 4.0, the proposed monthly bills.

A. Can you repeat the exhibit?

Q. A-16, Schedule F, 4.0.

A. I have it open.

Q. So if I'm in this exhibit, I can answer question. I can either lead you on this question or I can ask it the other

way, and I'm not sure which is more efficient, but I'm -- I'm -- I want to get to the -- the sheets of this exhibit that correspond with those GPD rates that we've been looking at in the tariff. And I think that starts on page 26, but please -- please correct me if it doesn't.

A. Your correct. It starts on page 26.

Q. So in columns F and K, you provide proposed unit costs for GPD voltage level one for the two seasons, correct? Depending on the -- the usage?

A. Correct.

Q. And depending on the usage and the season, voltage level one ranges from 6.4 cents. Sorry, depending on the voltage, the season, and the usage, the unit rate for level one ranges from 6.4 cents to 7.6 cents per kilowatt hour, right?

A. Correct.

Q. And on the very -- on the next page, we have interruptible, and on the page after that, we have voltage level two, correct?

A. Correct.

Q. So, again, just relating what's in the tarrif sheets that we were looking at to how this -- you know all -- all boils together or -- or synthesizes together to a unit cost for voltage level two, depending on the usage, the season, the -- the -- the unit cost for level two ranges from 7.5 cents per kilowatt hour to 8.9 cents per kilowatt

hour, correct?
A. Yes.
Q. And then if we skip page 29, because that's also interruptible and go to page 30, we find for voltage level three that those rates on the same basis, proposed rates are range from 8.1 to 9.5 cents per kilowatt hour. Correct?
A. Correct.
Q. There is in this comparison -- comparison of present and proposed monthly bills, there is no LED rate page, correct?
A. Correct, we haven't built that into this exhibit.
Q. Okay. If we -- so I'm going to flag that we're going to -- I'm going to have you look at a confidential exhibit now and maybe you can give me the information I'm asking for in the public record or maybe you cannot, and I will walk you through what I'm asking for, and then you and your counsel can make that determination. So I want to go to confidential Exhibit A-70 now.
THE COURT: All right, Ms. Horne, are you still with us?
MS. HORNE: I am Judge, but I will sign off.
THE COURT: All right. Thank you.
BY MR. BZDOK:
Q. Ms. Connolly, do you have A-70 up?
A. I have a printed version of that exhibit, I'm not sure if

there's a spot where confidential exhibits are housed separately.

Q. I know they're not in the SharePoint in any way. And typically if we're proposing when we e-mail it to the parties, if you have access to your work paper, I'm actually looking at your -- your Excel version of it, but whatever -- whatever works for you is fine with me to look at. And I can tell you what I'm going to ask you, and you and your counsel can determine whether it needs to be done on a confidential record or not. Is that -- is that fair?

A. Yes.

Q. Okay. So what I'm going to ask you -- so first of all I'm going to name a couple of rows, which I assume is not confidential. So here's -- here's what I want to talk about. So -- so I want to talk about the total energy in megawatt hours for the -- for -- for the period forecasted in A-7. So the total number, which is line 15, Column O, and I want to talk about the total LEDR revenues, which is line 38 Column O. And in both those instances, I'm looking at the exhibit line in column numbers, not the word paper, and column, and line numbers. So the -- the things that I'm hoping you can confer about are whether those two values are -- those two sum value are confidential.

THE COURT: If I can just interrupt for a second. I -- I understand that someone just joined this

hearing momentary or a moment ago. Can that person identify themselves, please?

MS. MISKHO: Yes, it is Alex Miskho. I work with Mark Templeton.

THE COURT: All right. Thank you, Alex. Have you signed a nondisclosure certificate for this case?

MS. MSKHO: Yes. I have.

THE COURT: All right. Thank you very much. Please proceed.

MS. UITVLUGT: Mr. Bzdok, as a point of clarification, are you asking her if these numbers are higher or lower than something in the public record, or are you asking her to state the numbers?

MR. BZDOK: I'm asking whether she can state the numbers in the public record or whether we need to do that in confidential.

MS. UITVLUGT: I would ask that that be said in a confidential record. If you wanted to do higher or lower, I think we could do it in a public record.

MR. BZDOK: Okay. I'd like to get the numbers, because then we're going to relate the numbers to each other and I'm going to get that number as well. So, Your Honor, I don't know if it makes sense to shift to a confidential record now, if it makes sense to take a lunch break and do it open in a confidential record after that or however you wish to proceed.

THE COURT: No. Why -- why don't we -- why don't we continue for now, thank you.

MR. BZDOK: Okay. So it is the understanding now that we're in a confidential record that will not be published on the docket.

(Transcript continues on page 196 of the confidential record.)

(Transcript continues from page 512 of the confidential record.)

MR. BZDOK: Your Honor, at this time, I'm going to shift, I guess some topics if -- I don't know what you're thinking is in terms of the -- the midday break, but this -- this -- this -- this would be a logical point on the exam for that, but I'm happy to continue well depending on your and the witness's desires.

THE COURT: I typically try to go for 90 minute sessions, if you will. And since we had the hearing, for lack of a better term on the motion I was thinking we'd go to 12:45-ish.

MR. BZDOK: Okay.

BY MR. BZDOK:

Q. Ms. Connolly, I want to talk next about the proposal to do facility's allowance to the LED rate.

A. Okay.

Q. Which you outlined at the top of the exam. You mentioned you outlined on page 12 of your direct testimony and then respond to my witness on that topic at pages four and five of your rebuttal testimony. Do you remember that?

A. Yes.

Q. So, let's just put some history on the board first. The LED rate was first approved in December 2021 in ex parte filing in case number U-21160. Is that right?

A. Yes.

Q. Consumers filed that application November 4, 2021 and amended it December 17, 2021. Does that sound familiar?
A. That sounds correct.
Q. The commission approved it four days after Consumers amended it on December 21, correct?
A. Yes.
Q. So all in maybe about 6 weeks or so from when it was proposed, correct?
A. Correct.
Q. At that time, the rate that was approved ex parte and that timeframe did not include a provision for a facility's allowance for the LED rate for Consumers Energy, correct?
A. That's correct.
Q. Since that time, Consumer have sought to add a facility's allowance to the LED rate in three cases prior to this one, U-21224, 21389, 21585, is that right?
A. That's correct.
Q. Your proposal in this case based on your direct testimony on page 12 is to calculate the facility's allowance based on the incremental distribution and system contribution charge revenue overall. Does that sound right?
A. Yes.
Q. That methodology is not set forth in the proposed tariff filing, correct?
A. Correct.
Q. The tariff filing says is:

"A facilities allowance specified in the contract for electric service."

Right?

A. That's correct.

Q. Generally speaking to date, the -- the LED contracts which specify all this are not filed for approval with the commission, correct?

A. That's correct.

Q. In addition to seeking approval to include a facility allowance going forward in your direct testimony, you also propose to provide a facility's allowance to LED rate customers who have already signed contracts with Consumers Energy, is that right?

A. I don't believe that was in my direct, but it was in my rebuttal testimony.

Q. Give me just a second. Okay. So with that correction about where it appears, you do agree that the proposal in this case is that if a facilities allowance is approved, it can be retroactively provided to customers who have already signed an LED contract and or -- and or are already taking service from the company into that rate, correct?

A. That is correct.

Q. How would that work? So -- so in other words -- well, if you can answer the question as I phrased it, please go ahead, it looks like you were about to. So please go

ahead.

A. Part of the development rate includes an incremental distribution charge that is specific to each customer. The incremental distribution charge is based on the cost of the distribution facilities to serve that customer. So to the extent that a facility's allowance was offered to the customer, we would take -- we would calculate the facility's allowance and offset the distribution investment amount and recalculate the incremental distribution chart.

Q. You said cal -- we would calculate the facility's allowance amount, and then you said something and then you said reset the distribution charge. Can you -- can you just repeat it, so I can get it down?

A. We would calculate the facility's allowance that we could offer the customer, and we would use that allowance to offset the distribution cost to serve that customer, and then we would use that new distribution amount to recalculate the incremental distribution charge?

Q. Okay. Thank you. So what I'm trying to get at -- I'm not sure how to ask it exactly to articulately ask it is -- the customer -- for the customers to whom this would be applied retroactively, they have been paying a distribution charge so far since they -- since they started taking service, that was set at a level that did not include a facility's allowance right?

A. Correct.
Q. And then the facility's allowance will be -- would be calculated if this proposal was approved, and that amount would then reduce the distribution charge, correct?
A. That's correct. We would then recalculate that distribution charge for the remaining term of the contract.
Q. So it would be -- it would be a reduction in the distribution charge that -- I'm going to try to ask it a different way, because I'm not doing it very well. So maybe we can use an example, because that might be more concrete. Normally when a facilities allowance is calculated, it's calculated on a projected marginal revenue for distribution and system contribution. Right?
A. Correct.
Q. And that marginal revenue is calculated over the life of the LEDR contract?
A. Our proposal in this case is to limit it to a 5 year period.
Q. Okay.
A. So it would be the projected marginal revenue over the 5 year period?
Q. Okay. So if I'm a -- if I'm an LEDR customer and I don't have a facilities allowance and facility allowance gets approved in this case and also gets approved for a retroactive application. And I'm in your 20 year

contract. Am I getting that allowance as a reduction in my distribution charge for the next five years or something else?

A. We would recalculate the incremental distribution charge for the remaining term of the contract. So it would not -- we would not apply it as a 5 year reduction, we would recalculate their incremental distribution charge based on the facilities allowance for the remaining term of their contract.

Q. Would it be calculated as if -- maybe I'll ask you clunky way. Are they getting somehow credit for overpayment in the price period on the idea that they would have had the facility's allowance, so they would have been paying less?

A. I don't believe they would get any credit for overpayment. I believe the way that it would work, if approved, is that we would take the initial calculation where we calculated their incremental distribution charge. That's a levelized charge over the life of the contract. So it's -- it's one charge. We would take that calculation. We would update it for what has actually occurred to date, and then we would include the facilities allowance that was approved. We would use that as an offset to the distribution cost that we initially assumed for the customer, and we would recalculate that incremental distribution charge going forward.

Q. Okay. So you're taking a delta essentially between what

they would have paid without, but between what they will pay for the remaining years of the contract with and without the facility's allowance, and you're spreading that difference as a reduction of the distribution charge over the remaining years of the contract?

A. Yes, correct.

Q. Thank you. Without disclosing any customer, specific customers or costumer related information. How many of these folks are there out there? How many of these customers are there who would receive retroactive application if this proposal was approved?

A. My understanding is that there were two contracts or two -- two customers, two contracts where we specified that we were proposing a facility's allowance, and if approved, it would apply to those customers.

Q. Okay. Without getting into the details, at least not at this point, those are the -- those are the customers that were in those two Hayward confidential attachments that you were referenced in some discovery.

A. That's correct.

Q. Okay. Okay. All right.

MR. BZDOK: Your Honor, we have a proposed exhibit in Ms. Connolly's folder, it's proposed Exhibit MEC-27, it's a discovery response related to page 4 of her rebuttal testimony, and I'm going to move to admit. Hold on. Yeah, I'm going to move to admit that one, without

any questions.

THE COURT: And, again, that was Exhibit MEC-27, is that right?

MR. BZDOK: Correct. Discovery response MNSC CE-0764.

THE COURT: Are there any objections to the admission of this exhibit?

Hearing none. Exhibit MEC-27 is admitted.

(At 12:29 p.m., Exhibit MEC-27 admitted).

MR. BZDOK: Thank you.

THE COURT: Mr. Bzdok. Might this be a good place to break?

MR. BZDOK: Certainly.

THE COURT: All right. Why don't we do that.

It's 12:29. So we will reconvene in an hour at 1:30.

(Off the record at 12:29 p.m.)

(Back on the record at 1:33 p.m.)

THE COURT: All right. We are back on the record.

THE COURT: We're in the middle of cross-examination of Ms. Connolly. Mr. Bzdok, please proceed.

MR. BZDOK: Thank you, Your Honor.

Q. Ms. Connolly, I'd like to direct you now to your rebuttal testimony at page 5 on the topic of retroactive of the

facilities allowance if one is approved in this case. In testimony on page 5 of your rebuttal, lines 5 through 12, you talk about certain customers having already signed to take service under LEDR and the part of the negotiation with those customers was around potential for a future allowance. And their contracts containing language related to that, I'm -- I'm paraphrasing you high level, but is that seem that's in the neighborhood of what you were talking about here?

A. Yes, that's accurate.

Q. Great. In the -- do you still have access to the SharePoint?

A. Yes.

Q. Okay. So in the SharePoint, within the MNSC folder here in the exhibits folder, Lauri -- Laura Connolly folder, there is a proposed Exhibit MEC-28. Which is a discovery response to MNSC CE-0765.

A. I have it open.

Q. Great. Here we ask you some questions about that line of rebuttal. The lines of rebuttal testimony, correct?

A. Yes.

Q. And in response to those questions in -- in each answer, there is the two confidential attachments, CE-0478, Hayward Attachment 3-A confidential and you got a specific part in there and also Hayward Attachment Five confidential, correct?

A. Yes.
Q. I'm going to move to admit MEC-28 at this time.
THE COURT: Are there any objections to the admission of -- of this exhibit?
Hearing none. MEC Exhibit -- excuse me. Exhibit MEC-28 is admitted.
(At 1:36 p.m., Exhibit MEC-28 admitted)
BY MR. BZDOK:
Q. You have access to those two attachments, Natasha Fowles from my office e-mailed those to the parties with some con -- as -- as part of a confidential exhibit set yesterday or 4:18 p.m.
A. Yes, I can open them. Just one minute.
Q. Great. So for the record, I'm referring to proposed confidential Exhibit MEC-29-C, which consists of both of the two attachments identified, that I just identified confidentially, that was served to all the parties on the NDC list at 4:18 p.m. yesterday.
THE COURT: Mr. Bzdok, can you confirm what was the number of that exhibit?
MR. BZDOK: 29-C, MEC-29-C.
THE COURT: Thank you.
BY MR. BZDOK:
Q. Ms. Connolly, do you have access to the -- I think you have confirmed, you're able to open and see those?
A. I have it open now.

Q. Okay. This may be a question for your counsel and or you. My intent is to ask you specific questions about the language of section 9-J which is referred to in the in -- in the discovery response we just admitted. As well as to ask you about the contracts and so I'm not going to ask you any customer information or anything like that, but I'm going to ask you about those two topics. And so I don't know if we need to do that and confidential I can do that in public.

MS. UITVLUGT: It can be done in a public record, Chris.

BY MR. BZDOK:

Q. Thank you. So within Exhibit MEC-29-C, let's look at the first attachment. First attachment 3A, which is a large economic rate LED contract for electric service. And at the bottom there are a couple of dates under execution of agreement. There are a few dates. There's a -- there's an execution of agreement date that's highlighted in yellow as June 21, 2023. Do you see that?

A. Yes.

Q. And then there are signature dates of June 27, 2023 for the anonymous customer and July 11, 2023 for the co -- Consumers Energy, correct?

A. Correct.

Q. Okay. The language that you pointed us to in the public discovery response was section 9-J, which is on page 4 of

the contract. And I'll grab an exhibit page in a second here. Also exhibit page 4. Are you able to locate 9J?

A. Yes.

Q. Okay. So 9-J states:

> "No later than June 1, 2023, the company shall file with the NPSC, an application to amend rate LED to allow for rate LED customers to qualify for the contribution of construction credit. Customer shall cooperate with the company to facilitate this filing and approval."

Correct?

A. Yes.

Q. And what's being referred to here as the contribution and at a construction credit is for practical purposes, the facilities allowance, that stuff in these recent cases?

A. That's correct.

Q. Okay. Now Consumers filed case U-21389 on May 1, 23. Does that sound right?

A. Yes.

Q. Okay. In 21389, Consumers included in its rate case, an application to amend rate LED to allow for customers to qualify for a credit or facility's allowance, is that right?

A. Yes.

Q. So Consumers performed the obligation in this contract in or around the time the contract was executed, correct?

A. Yes. It looks like we filed the case prior to this contract being executed.
Q. Okay. Is there any language else -- I'm asking these questions in the same sense that you talked about them in your rebuttal. Lines we looked at, in -- in your understanding, just the standpoint and not asking you for any legal interpretations. But I -- I -- in -- in your understanding, is there language in 9-J or elsewhere that you're aware of, that says must apply any approved CIAC credit or allowance to this customer?
A. No. I don't think that's explicitly laid out in the contract.
Q. Would you agree the contract also again from the same in the same sense and not a legal conclusion, the contract does not obligate Consumers to -- to continue to keep trying to obtain approval of said credit or allowance if the attempt in 21389 was unsuccessful?
A. I agree. It wouldn't obligate us to keep trying.
Q. Okay. I'm going to ask you similar questions about attachment five, the confidential attachment five, which is also in exhibit MEC-29-C. So, I'm going to scroll down then to attachment five begins here on page 16 of the confidential exhibit. Do you see that?
A. Yes.
Q. Okay the dates on that contract are February 2, 2024 and February 7, 2024, is that right?

A. Yes.
Q. So if we go to page 4 of that contract, which is page 19 of exhibit MEC-29-C, we find language in section 9J, which you reference in MEC-28 discovery response, is that right?
A. Yes.
Q. Okay so there it says:

> "The company has filed with the MPSC an application to amend rate LED to allow for rate LED customers to qualify for the contribution and aid of construction or CIAC credit. As well as the possibility to use a day ahead energy pricing option, a proxy plant pricing option has also been proposed. If any such options are approved and customer wanted to take advantage of one or more of them, the provisions of section 9I would be triggered with any modifications to this agreement applying on a prospective basis."

Did I read that accurately?
A. Yes.
Q. And I'm not going to read section 9I, but section 9I high level refers to the customer's ability to request changes to its rates in accordance with changes in the read book, right, is that fair?
A. Yes.
Q. At the time this contract was entered into in February of 2024, case U-21389 was still pending, is that right?

A. Yes.
Q. So the reference to the filing of an MPSC application with these proposed electricity LED rate terms and provisions about CIAC, day ahead energy pricing option, and proxy plant pricing option, we're referring to the pending application in 21389?
A. That's correct.
Q. And the outcomes in 21389, looking at 9J, where the -- the CIAC credit was not approved, the use of a day ahead energy pricing option was approved, and the proxy plant pricing option was not approved. Is that correct?
A. Yes.
Q. Did -- again asking you in the same sense I was asking you earlier from a business perspective and not for any legal interpretations, did -- was -- are you aware of anything in this contract which obligated Consumers to keep trying in future cases to obtain approval of either or both of the CIAC credit or the proxy plant pricing option?
A. No.
Q. Okay. Consumers have, in fact, not continued to seek approval of the proxy plant pricing option, correct?
A. That's correct.
MR. BZDOK: Your Honor, at this time, I'm going to move to admit proposed exhibit MEC-29-C.
THE COURT: Are there any objections to the admission of this exhibit?

Hearing none. Exhibit MEC-29-C is admitted into the confidential record.

(At 1:48 p.m., Exhibit MEC-29-C admitted)

MR. BZDOK: Thank you.

I'm going to stay in confidential for just a little bit longer and ask about a different topic -- well, oh, no. We're still -- we're still in public. Aern't we?

THE COURT: Yes.

MR. BZDOK: Okay. My notes reflect that we were going to be in confidential until and -- indicated we could stay in public. So I -- I need to check one other item. Anne and Laura, speaking just high level and not getting into specifics in paragraph 11 of these contracts. There is a -- there's a -- there's a -- there's some language about ceasing operation before the end of an agreement and about certain percentages of payment would be made depending on where in the term the agreement was. I don't know if that information can be discussed in public or needs to be discussed in confidential. And I'm sorry I'm sort of just bringing this one on you. I didn't review it. If it's helpful, I can also -- I think I can do this exam without a -- without any -- using any of the numbers. I'm just talking about the structure generally.

THE WITNESS: Unless Anne disagrees, I believe these percentages are laid out in the tariff, so that wouldn't be confidential.

THE COURT: Ms. Uitvlugt, do you have something to offer on this?

MS. UITVLUGT: I'm double checking the tariff.

THE COURT: Very good.

MS. UITVLUGT: I don't believe they'd be in Brittani's tariff, because we didn't propose any changes to them, so she doesn't include sheets that have no changes.

MR. BZDOK: I'm finding them. Excuse me. I'm finding them now in. Yes, I agree with you. I'm finding them on sheet D-7810 of the current tariff.

Your Honor, may I share the screen for a moment?

THE COURT: As long as it's not confidential. Sure, yeah.

MR. BZDOK: I'm -- I'm going to share the -- the current rate book. This I believe the tariff was also included in the MEC Exhibit 29-C, because they're attached to the contract.

MR. BZDOK: So I'm going to if it's okay. To refer just to the existing rate book, I can -- I can pivot and do the exam on that.

MS. UITVLUGT: I think either way, if you're containing the exam to what's in the tariff language, which is also in the contract, I'm okay with it done publicly. Okay.

BY MR. BZDOK:

Q. So, Ms. Connolly, referring, based on the discussion -- we had -- we have -- have -- had -- we've been having -- excuse me. Paragraph 11 of these rate LED contracts contain language from the rate LED tariff found in the company's current rate book sheet number 78.10, is that right?
A. Yes.
Q. Okay. And so referring to sheet 78.10, this indicates that so -- so there are terms and conditions in maximum contract term and a minimum term, and then there is this provision about if the customer ceases operation before completion of the contract term, correct?
A. Yes.
Q. And then it says the customer if -- if that happens the customer shall pay the remaining balance for any transmission and distribution system investments specified in the contract to provide service to the customer according to the following schedule, correct?
A. Correct.
Q. And then there are -- there is sort of a step down schedule of how far into the -- how far into the contract term the customer is and what percentage of the remaining balance the customer pays, correct?
A. Correct.
Q. Okay these are these are incremental transmission and distribution system investments, correct? These are

charges for that?
A. The percentages are referring back to the transmission in distribution system investments. That would be specific to this customer.
Q. The -- I think that you said in -- early in the exam to -- that part of an LED or customers distribution charges are charges to recover incremental distribution system investments made to connect that customer through the distribution charge over the life of the contract? Correct?
A. Correct.
Q. And that's the portion out of which potentially a facility's allowance would be taken or adjusted?
A. Correct.
Q. Okay. You also, I think testified earlier today that transmission charges in the LED rate are collected through the PSCR and represent a marginal distribute -- transmission cost, correct?
A. That's correct.
Q. Okay. The -- is -- is it the case that there could be -- is it the case that so what I'm trying to understand, first of all there's two things I want to understand about this. So looking at one of these schedule items I can see, you know let's go -- go down a couple just for some example there's a -- there's a lot, the third row down says more than 60 to 70% of the

contract term, and there's a 67%, correct?
A. Correct.
Q. And so I take it what this is reflecting is if the customer is that far into the contract term and they -- they still have a remaining balance of incremental distribution and transmission investment costs that they're paying through the distribution charge?
A. They wouldn't pay transmission through the distribution charge but the -- any incremental distribution remaining on that distribution charge.
Q. Okay. And any incremental transmissions through the transmission charge?
A. Correct.
Q. Okay. And so what this is saying, I think, is that the customer would not be responsible in a case of operation system for or -- or let me rephrase it, would be responsible if there's 60 to 70% through their term for 67% of the remaining balance of the revenue requirements for the incremental distribution and transmission investments made to connect them, is that right?
A. That's my understanding, yes.
Q. Okay. How is the other 33%, what happens to the other 33% in this in this example we're discussing.
A. I believe the idea with this schedule as it's laid out is that they would have already paid some of -- of that during the initial term of the contract.

Q. Fair. And you don't want to be argumentative. I -- I'm seeing that is -- this is a percentage of the remaining balance that they're paying and not the original balance, is that the right interpretation?

A. Yeah. Sorry. I unders -- I understand what you're asking. Given that clarification, I -- I'm not sure what happens to the remaining 33%?

Q. Does it get paid into general rates?

A. I believe that it would, but I'm not a 100% sure. I haven't reviewed this language in detail.

Q. Okay. Thank you. I'm going to stop sharing.

MR. BZDOK: I'm going to move to admit some -- in order to streamline things, I'm going to move to admit, Your Honor, and at this time some of the other proposed discovery response exhibits that we have in the SharePoint. I'm going to move to admit them without questions, certainly happy to ask questions about them, but just trying to trim some time here.

So those exhibits, I can been do them one at a time, or I can do them as a group, but they will be exhibit MAC-20 MNSC CE-0766, MEC-31, which is discovery response, MNSC CE-0767, and MAC-36, which is MNSC CE-0939. And I'm going to add one more, sorry. MEC-34, which is MNSC CE-0938.

THE COURT: And none of these are confidential, correct?

MR. BZDOK: Correct. And they're all responses from Ms. Connolly.

THE COURT: Are there any objections to the admission of these exhibits?

Hearing none. Exhibits MEC-30, MEC-31, MEC-34, and MEC-36 are admitted.

(At 2:02 p.m., Exhibit MEC-30, MEC-31, MEC-34, and MEC-36 admitted)

MR. BZDOK: Thank you, Your Honor, just a moment to review my notes and my exhibits.

I have one more, which is one of the other confidential exhibits that was circulated yesterday at 4:18 p.m. that is proposed exhibit MEC-35-C which is discovery response -- confidential discovery response attachment MNSC CE-0209, the letter agreement between Consumers Energy company and the recently announced data center, which is also discussed in Ms. Connolly's rebuttal.

THE COURT: Are there any objections to the admission of this exhibit?

Hearing none. Exhibit MEC-35-c is admitted to the confidential record.

(At 2:04 p.m., Exhibit MEC-35-C admitted)

MR. BZDOK: Thank you, Your Honor.

Ms. Connolly. I appreciate your time and your answers today, and that concludes my questions for you.

THE WITNESS: Thank you.

THE COURT: Is there anyone else who has cross-examination for this witness?

Hearing none. Ms. Uitvlugt, do you have any questions of this witness?

MS. UITVLUGT: May I have five minutes, Your Honor?

THE COURT: You may, we're off the record.

(Off the record at 2:05 p.m.)

(On the record at 2:10 p.m.)

THE COURT: All right. We are back on the record. Do you have any questions, Ms. Uitvlugt?

MS. UITVLUGT: No redirect, Your Honor.

THE COURT: All right. Thank you. Again is anyone else present who wishes to question this witness?

Hearing none. Ms. Connolly you are excused, thank you for your time.

THE WITNESS: Thank you.

THE COURT: Previously Ms. Uitvlugt moved for the admission of exhibits sponsored by Ms. Connolly, including Exhibit A-16, I believe with various schedules identified. Am I correct, Ms. Uitvlugt that this exhibit with the schedules refer to begin with the letter F, that there are other schedules that are part of this exhibit, A-16?

MS. UITVLUGT: I believe so, Your Honor.

THE COURT: Okay. Well, I'm -- I'm asking, because I had a -- a court reporter suggested to me that admitting an exhibit when only some, but not all of the various schedules affiliated with that exhibit have not been admitted is improper, and she's convinced me. So I'm going to suggest to you that we will circle back to the admission of Exhibit A-16, when the subsequent witnesses have offered testimony or their testimony has been offered in support of other schedules to that exhibit. So at this time, Consumers and you. Correct me if I'm wrong, Ms. Uitvlugt, has proposed the admission of exhibits A-66 through A-70 with A-69 and A-70 being confidential. Those are proposed for admission. Are there any objection to the admission of those exhibits? Hearing none. Exhibit A-66 through A-68 are admitted into the public record and exhibits A-69 and A-70 are admitted into the confidential record.

(At 2:13 p.m., Exhibit A-66 through A-68 admitted to public record and exhibits A-69 and A-70 admitted to confidential record)

MS. UITVLUGT: Thank you, Your Honor.

THE COURT: Thank you. I believe we're now going with Mr. Guinn, is that correct?

MS. UITVLUGT: That's correct, Your Honor.

THE COURT: All right. And Ms. Uitvlugt.

MS. UITVLUGT: One second, Your Honor, we have

to shuffle places.

THE COURT: All right. We'll go off the record for a moment.

(Off the record at 2:13 p.m.)

(On the record at 2:17 p.m.)

THE COURT: All right. We are on the record. Sara, can you swear in the witness, please?

THE COURT REPORTER: Yes, Your Honor, Mr. Guinn, could you please raise your right hand? Do you swear that the testimony you're about to give in this matter will be the truth, the whole truth, and nothing but the truth?

THE WITNESS: Yes.

THE COURT REPORTER: Thank you.

THE COURT: Mr. Guinn. Can you confirm that you do not have any notes, papers, or documents in front of you other than pre file testimony exhibits for discovery responses in this case?

THE WITNESS: Yes.

THE COURT: Thank you. Ms. Uitvlugt?

MS. UITVLUGT: Thank you, Your Honor.

DIRECT EXAMINATION

BY MS. UITVLUGT:

Q. Good afternoon, Mr. Guinn. Can you please state your full name and business address for the record?

A. Quentin Anthony Guinn, full address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?
A. Consumers Energy Company?
Q. And what is your role at Consumers Energy?
A. I am a Contract Strategy Manager.
Q. And did you cause to be pre filed in this matter the direct testimony of Quentin A. Guinn, which consists of a cover page and 82 pages of questions and answers?
A. Yes.
Q. Did you also cause to be pre filed in this matter the rebuttal testimony of Quentin A Guinn, which consists of a cover page and six pages of questions and answers?
A. Yes.
Q. And do you have any changes you wish to make to either your direct or rebuttal testimony?
A. No.
Q. And if I were to ask you these questions today, would your answers be the same?
A. Yes.
Q. And are you adopting these as your sworn testimony in this case?
A. Yes.
Q. And did you also cause to be pre filed in this matter some exhibits associated with your direct and/or rebuttal testimony?
A. Yes.
Q. And are those Exhibit A-12 Schedule B-5.6, Exhibit A-101,

exhibit A-102, Exhibit A-103, Exhibit A-104, Exhibit A-105, and Exhibit A-106.

A. Yes.

Q. And do you have any changes you wish to make to any of your exhibits in this case?

A. No.

Q. And were those exhibits prepared by you or at your direction?

A. By me or and/or by direction.

MS. UITVLUGT: At this time, Your Honor, I would ask that the direct and rebuttal testimony of Mr. Guinn be bound into the record and I would move for the admission of Mr. Guinn's exhibits at the end of the cross-examination and subject to your ruling with Ms. Connolly, I note that Exhibit A-12, Schedule B-5.6 would be held back until all the rest of the exhibit is emitted.

THE COURT: Thank you. Just confirmation Ms. Uitvlugt, none of the direct or rebuttal testimony is confidential, is that right?

MS. UITVLUGT: That is correct.

THE COURT: All right. Are there any objections to the admission of the direct and rebuttal pre filed testimony of this witness?

Hearing none, the direct and rebuttal pre filed testimony of Quentin Guinn is bound into the record. Ms. Hillyer?

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Quentin A. Guinn and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Capital Asset Strategy Manager.

Q. What are your responsibilities as Capital Asset Strategy Manager for Consumers Energy?

A. As Capital Asset Strategy Manager, I am responsible for providing support and direction for Facilities strategy development, compliance, resource planning, and regulatory proceedings. The Facilities execution plan ranges from activities related to electric operations to those involving corporate operational areas of Consumers Energy. Facilities' asset portfolio consists of over 60 buildings and includes the corporate office, storerooms, distribution centers, maintenance garages, service centers, welding and fusion workshops, learning and development buildings, coal generation, wind generation, gas compression, and hydroelectric sites. My responsibilities include regulatory compliance, rate case strategy and execution, corporate policy administration, organizational vision, and resource planning for field execution. I also provide oversight to Fleet Acquisition supporting the Company's current and long-term capital replacement strategy, vehicle disposition, licensing, rentals, and internal electric vehicle ("EV") strategy. Finally, I provide oversight to the Company's Investment Recovery Center ("IRC") function, which handles the disposition of surplus Company assets.

Q. What is your formal educational experience?

A. I hold a bachelor's degree in economics from Yale University, located in New Haven, Connecticut, and a Juris Doctorate degree from Washington University, located in St. Louis, Missouri.

Q. Would you please describe your previous work experience?

A. In 1999, I started my career at Consumers Energy as a Contracts Analyst. In 2000, I began a series of changing roles, with increasing responsibility, from Contracts Supervisor to Director of Contract Services. In each successive role, I led teams of Contract Analysts and Contract Administrators who were responsible for a broad range of construction, maintenance, consulting, information technology, and engineering contracts. The responsibilities of these teams included sourcing and evaluating contractors and consultants, developing scopes of work, competitively bidding work, negotiating agreements, and administering contracts. In 2013, I began work in a series of successive roles focused on data, analytics, performance, and work management culminating in my current role as Capital Asset Strategy Manager.

Q. What is the purpose and scope of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's costs related to the Electric business portion of Facility Operations and to support the Company's costs related to the electric business portion of Fleet services. To that end, I will:

- Describe the Facilities and Shared Services function;
- Describe the methodology employed by Facility Operations ("Facilities") for evaluating the health of its various facilities;
- Support the reasonableness and prudence of the capital expenditures for Asset Preservation for the historical year ended December 31, 2024, the bridge period beginning January 1, 2025 and ending April 30, 2026, and the projected test year ending April 30, 2027;

- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") expenses for Facilities and Shared Services for the historical year ended December 31, 2024, the bridge period beginning January 1, 2025 and ending April 30, 2026, and the projected test year ending April 30, 2027;
- Describe the Company's Fleet and how it is managed through Fleet Services;
- Explain the Company's Fleet Replacement Planning Process;
- Explain the Company's Fleet Electrification Strategy; and
- Sponsor the Company's Fleet capital spending projections.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or "the Commission")?

A. Yes. I have provided testimony on behalf of Consumers Energy in Case Nos. U-21148, U-21224, U-21308, U-21389, U-21490, U-21585, and U-21806.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (QAG-1)	Schedule B-5.6	Summary of Actual & Projected Capital Expenditures Facilities & Shared Services and Fleet Services;
Exhibit A-101 (QAG-2)		Summary of Actual and Projected O&M Expenses Facilities & Shared Services;
Exhibit A-102 (QAG-3)		Detailed List of Projected Electric Capital Expenditures Facilities & Shared Services;
Exhibit A-103 (QAG-4)		Fleet Responsibility Costs;
Exhibit A-104 (QAG-5)		Detailed List of Projected Electric Capital Expenditures Fleet Services for the Years 2024, 2025, 2026 and test year 12 months ending April 30, 2027;
Exhibit A-105 (QAG-6)		Summary of Fleet Tooling Actual & Projected Capital Expenditures; and

Exhibit A-106 (QAG-7)	New Construction & Renovations Plan Summaries.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. Please describe the exhibits you are sponsoring.

A. Exhibit A-12 (QAG-1), Schedule B-5.6, details the actual and projected capital expenditures related to Facilities and Shared Services and for Fleet Services for the calendar year 2024, bridge period (16 months ending April 30, 2026), and the projected test year 12 months ending April 30, 2027. Exhibit A-101 (QAG-2) details the O&M costs related to Facilities and Shared Services. Exhibit A-102 (QAG-3) identifies Facilities and Shared Services projects and the projected capital expenditures related to those projects and programs. Exhibit A-103 (QAG-4) provides details of the Company's fleet responsibility dollars. Exhibit A-104 (QAG-5) provides details of the Company's Fleet acquisitions in the historical year 2024, bridge period (16 months ending April 30, 2026), and the projected test year 12 months ending April 30, 2027. Exhibit A-105 (QAG-6) is a Summary of Actual and Projected Fleet Tool Capital Expenditures for the historical year 2024, bridge period (16 months ending April 30, 2026), and the projected test year 12 months ending April 30, 2027. Exhibit A-106 (QAG-7) includes building assessments for the service center projects (Lansing, Hastings, Kalamazoo) and summary project schedules for all New Construction and Renovations projects included in this case.

Q. Please explain the Facilities and Shared Services function.

A. The Facilities and Shared Services function consists of the following support organizations: Fleet Services, Facilities, Real Estate, Contractor Oversight, and Supply Chain Materials Management. Facilities and Shared Services acquires, constructs, and maintains assets

required to support the functional areas of the business that serve the Company's customers.

Q. Are you addressing all support organizations related to Facilities and Shared Services in your direct testimony and exhibits?

A. Yes.

Q. What is the function of the Facilities organization?

A. Within Facilities and Shared Services, Facilities manages, maintains, and operates over 60 buildings comprising 3.2 million square feet of building space across the state of Michigan that allows the Company to serve customers across the state in an efficient and effective manner.

Q. How have Company facilities changed over time?

A. The Company experienced major growth in the area of Facilities during the 1950s and 1960s. Of its 60 buildings, nearly half were built or acquired during this period and remain in operation today. As a result, these buildings are now over 50 years old. The Company made no significant investment in its facilities and initiated no major renovations or construction of new buildings between 1970 and 2000 given competing customer investment priorities. In 2003, the Company constructed its One Energy Plaza headquarters building in Jackson. This construction marked the adoption of the open office concept (i.e. fewer hard wall offices) at the Company which, among other reasons, was adopted to foster a more collaborative work environment. Between 2000 and 2016, the Company also closed many facilities including 22 service centers across Michigan to adapt to shifting population trends in the state and to reduce costs for customers.

Q. What structural concerns or problems do these aging structures and facilities create for the Company?

A. Multiple major systems throughout these facilities, such as boilers, chillers, cranes, elevators, emergency generators, heating, ventilation, and air conditioning ("HVAC") systems, lighting, power distribution, paving, roofing, Uninterruptible Power Systems, and vehicle hoists are beyond their useful lives. Further, building materials in some facilities contain hazards such as asbestos and lead paint. Repairs on such aging infrastructure are not always cost effective and can lead to lengthy projects and significant renovation or replacement of entire structures. It is also increasingly difficult to identify and obtain adequate parts and to further locate the necessary expertise to work on aging equipment. In addition, these facilities were not designed to meet modern standards of energy efficiency.

Q. What concerns or problems do these aging structures and facilities create for the Company's customers?

A. The population and infrastructure of the state of Michigan look much different than they did in the 1950s and 1960s. In 1950, the population of Michigan was 6,407,000 with growth focused in urban areas. The state's current population is now over 10 million, with much of the growth since the 1960s having occurred in suburban areas. The locations of some of the Company's facilities no longer allow the Company to optimize service to customers. In these situations, longer response times and increased drive times make meeting service delivery standards difficult for the Company's employees who are dedicated to providing the best service to Consumers Energy's customers. The cost implications of these issues include but are not limited to higher transportation fuel costs,

accelerated wear and tear on vehicles, and reduced cycle time for truck rolls - all of which increase service costs to customers. This issue is particularly pronounced at the Lansing Service Center, as I will discuss in detail later in my testimony.

Q. What process does Consumers Energy utilize to evaluate whether to make capital investments in facilities?

A. The Company has been using a formal assessment process for several years that evaluates whether or not to invest in a facility by studying each facility's overall health beyond annual O&M expense. The Company plans to continue using this process and is enhancing it by incorporating the operational priorities of the Facilities organization's internal business partners (e.g., Electric Operations, Gas Engineering, etc.). Given the evolving nature of the workforce (i.e. with hybrid work) the Company is working to ensure its facilities are right sized and properly configured for the needs of the work.

Q. What is the formal assessment process related to facility health?

A. A formal assessment process was established in 2016 to determine the need for capital investments in facilities. The assessment process is re-evaluated every two years resulting in minor updates to the methodology to reduce subjectivity in scoring. The most recent assessment was completed in 2022. The Facilities Department consists of qualified, trained, and certified experts in architecture, HVAC, plumbing, and electrical that conduct the assessment. In that process, an evaluation is made, on a multi-category scale, of certain conditions and characteristics of the structure and functions of the facility being assessed. For each facility, each condition and characteristic is scored (with a score of 0 lowest to 5 highest per category), and then the facility is ranked on a multi-category scale (with an 80-point maximum score).

Q. What categories are included in the evaluation process of the Company's facilities?

A. Categories that are evaluated include: (i) safety (such as asbestos or other hazardous materials, traffic flow, and compatibility with surrounding areas); (ii) quality (such as workplace efficiency, employee comfort, and talent attraction and retention); (iii) cost (such as facility operating costs, space optimization, and energy efficiency); (iv) delivery (such as response times, driving distance within service territory, and sustainability of operations); and (v) morale (such as employee pride, wellness, and retention).

Q. How is the quality of each category identified above established?

A. The facility evaluated will fall within one of three quality designation categories depending on the score received. A score above 64 is designated as "Good"; a score of 48 to 64 is designated as "Serviceable," meaning that investment and/or replacement is needed; and a score under 48 is designated as "Poor," meaning that there are multiple systems failing at the facility. Facilities designated as "Poor" are typically candidates for replacement.

Q. What is the next step in the facility assessment?

A. Once the facility is initially evaluated and receives a quality designation, operational departments of the business then review and validate the raw scored ranking and adjust the ranking to reflect forecasted needs of the business. Facilities finalizes the score, and any facility that scores below a minimum acceptable level, 48 out of 80 points, may be a candidate for renovation or replacement.

Q. How does the Facilities organization consider the business needs of its internal business partners when selecting locations to target and how do facility health assessments and evaluations of business partner needs combine to create a prioritization plan for Facilities work?

A. The Facilities organization considers business partner needs by meeting on a regular basis with business partners to review their business plans and the resulting impacts on the facilities necessary to support these plans. The process begins with a 10 Year Long Term Facilities Plan. This plan is maintained by the Facilities organization and contains fundamental information about each facility such as the year the building was constructed, estimated years of useful life remaining in the building, dates of major milestones in the life of the building (e.g. significant renovations and building additions), etc. The 10 Year Long Term Facilities Plan is one of several inputs then used to inform creation of the Long-Term Financial Plan ("LTFP"). The LTFP is a five-year financial plan created in part from the aforementioned facility health assessments. Facilities organization engineers and other technical experts across the Company (e.g. Company environmental analysts) generate health assessments and develop capital investment priorities based on the health assessments (e.g. replacement of specific assets at specific buildings, preventive maintenance of specific building systems, work on a building envelope). These capital investment priorities are then reviewed by business partners for alignment with their business plans and can become projects incorporated into the LTFP. The ultimate list of capital investment projects incorporated into the LTFP is then derived from this collaboration between the Facilities organization and business partners. While considerable engineering rigor is applied to developing the facility health assessments, business partner

priorities do affect the ultimate list of projects incorporated into the LTFP. The Kalamazoo Service Center Project included in this rate case, for instance, was elevated in priority to address negative employee morale and hazardous material issues, among other factors, that resulted in nearly 40% of the Kalamazoo Service Center being closed to employees.

Q. Does this process ensure priority is given to Facilities projects critical to ensuring the Company can serve its customers?

A. Yes. The facility health assessments and aforementioned planning process produces a prioritized list of facilities for renovation or replacement that is aligned with both the need to preserve and maintain facilities assets and support business plans in providing optimal customer service. Buildings that are in poor shape or are otherwise suboptimal negatively impact the Company's ability to serve customers.

Q. Are there situations in which prioritization of projects might change even after development of the LTFP?

A. Yes. Though not typical, reprioritization of projects after establishment of the LTFP can occur. For example, several years ago the Company reprioritized development of a service center in Tawas to provide timely support to customers in the greater Tawas region and to reduce the workload impact on local first responders during response to emergency utility events. In another example, the Company revised its plans for the Kalamazoo Service Center Project included in this case. In this instance, after examining the impacts of the COVID pandemic on the workforce and changes the pandemic wrought in how work is performed, the Company revised its original plan to replace the Kalamazoo Service Center and instead decided to renovate portions of it as many of the building modifications

originally proposed became more costly due to supply chain issues and were also deemed no longer necessary to support the post-COVID workforce.

Q. Is the Company taking steps to ensure its facilities are right-sized given changes in the working environment?

A. Yes. The Company continues to monitor use of its facilities in a post-COVID work environment. Following the pandemic, the Company established expectations for in-person work for all employees at Company facilities. As a result, Company facilities are continuously evaluated for alignment with current and anticipated work trends. In cases where underutilized workspace has been identified, the Company has divested or examined divesting such space. For example, in 2020, the Company terminated lease agreements for over 30,000 square feet of previously leased office space at the Commonwealth Commerce Center in Jackson. The Company will continue to evaluate space utilization with the goal of eliminating underutilized space and aligning business needs with space requirements.

Capital Spending Overview

Q. What programs are included in the projected capital expenditures for Facilities?

A. As demonstrated in Exhibit A-12 (QAG-1), Schedule B-5.6, Facilities capital spending is divided into two programs: (i) Asset Preservation; and (ii) Other Equipment. Capital spending is broken down into multiple standard cost categories, including contractor, labor, materials, business expenses, and other (loadings, chargebacks). Most Facilities capital spending, as reflected in Exhibit A-12 (QAG-1), Schedule B-5.6, is for Asset Preservation, which is broken down into four portfolio categories: emergent repairs, asset replacement, new construction, and renovations.

Other Equipment

Q. What is included in the Other Equipment program?

A. Other Equipment includes capital investments for wellness equipment; computer equipment; print equipment; Real Estate tools and equipment; Supply Chain tools and equipment; and Facilities tools. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, the Company is projecting to spend $838,000 on Other Equipment in the bridge period and $670,000 on Other Equipment in the test year.

Q. Can you elaborate on what the various categories of Other Equipment spending represent?

A. Wellness Equipment consists primarily of equipment used by Operations personnel and others in the Company's fitness centers. Computer Equipment includes computers acquired for use by Facilities and Shared Services personnel outside of routine lifecycle replacements. These include acquisitions of computer equipment obtained for a specialty use (e.g. a plotter) or replacement of computer equipment that fails prematurely for various reasons. Print Equipment consists of large copying and printing equipment for the Company's Mail Room. Real Estate Tools and Equipment consists primarily of survey equipment. Supply Chain Tools and Equipment consists of tools and equipment acquired for material storerooms such as shelving.

Q. How did the Company determine this level of investment for Other Equipment?

A. Investment levels for Other Equipment are established annually as part of the annual budget setting process. Levels of investment are set to meet identified needs of the business.

Emergent Repairs

Q. What capital expenditures are included in the Emergent Repairs portfolio category?

A. Emergent Repairs includes unplanned corrective maintenance and break fix repair of assets. As shown in Exhibit A-102 (QAG-3), the Company is projecting to spend $1,344,000 in the bridge period and $2,706,000 in the test year on emergent repairs. The Company maintains data on the age, condition, and maintenance history of its major building system assets. This data, in conjunction with historical spend, is used to forecast projected spending on unplanned corrective maintenance and break fix repair of assets.

Asset Replacement

Q. What capital expenditures are included in the Asset Replacements portfolio category?

A. The Asset Replacements portfolio category includes capital replacement of paved surfaces such as parking lots and driveways; roofing; mechanical and electrical equipment in buildings, and furniture. Exhibit A-102 (QAG-3) shows the Asset Replacement portfolio category broken down across the different types of work. As shown in Exhibit A-102 (QAG-3), the Company is projecting to spend $6,563,000 on Asset Replacements in the bridge period and $8,810,000 on Asset Replacements in the test year.

Q. How are Asset Replacement projects targeted?

A. Similar to the aforementioned facility health assessments, asset condition assessments are performed by Facilities engineers on a regular basis, along with input provided by external industry professionals. For example, for roofing assets, a portion of roof sections is inspected annually such that all roofs are inspected once every three years. The condition of each assessed asset is ranked following standard industry-recognized methodologies.

Those assets assessed to be below acceptable condition are targeted for renovation or replacement.

Q. How does the Company identify locations for paving projects?

A. The condition of paving assets is evaluated following standard industry practices on a rolling five-year basis with a condition assessment performed annually for 20% of Company sites. Paving assets are prioritized for replacement based on the lowest assessed condition index score. Paving projects may include other related enhancements to paved surfaces such as new drainage or new lighting.

Q. How did the Company determine the amount of needed investment in paving projects for the bridge period and the test year?

A. The total amount of needed investment in paving projects begins with the five-year historical average spend. Paving condition assessments are then used to determine how that spend is allocated. While investment in paving projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. How does the Company identify locations for roofing projects?

A. The condition of roofing assets is evaluated on a rolling three-year basis with a visual inspection and detailed infrared inspection performed annually for 33% of Company sites. Roofing assets are prioritized for replacement based on the lowest assessed condition index score.

Q. How did the Company determine the amount of needed investment in roofing projects for the bridge period and the test year?

A. The total amount of needed investment in roofing projects begins with the five-year historical average spend. Roofing condition assessments are then used to determine how that spend is allocated. While investment in roofing projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. How does the Company identify locations for mechanical and electrical projects?

A. The condition of mechanical and electrical assets is evaluated by Facilities engineers for all Company sites. Based on the results of these evaluations, targeted maintenance work is performed on mechanical and electrical assets. Where the condition of mechanical and electrical assets is determined to be below an acceptable threshold for targeted repair or maintenance, the mechanical and electrical assets are prioritized for replacement based on the results of these evaluations.

Q. How did the Company determine the amount of needed investment in mechanical and electrical projects for the bridge period and the test year?

A. The total amount of needed investment in mechanical and electrical projects begins with the five-year historical average spend. Mechanical and electrical condition assessments are then used to determine how that spend is allocated. While investment in mechanical and electrical projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. How does the Company identify locations for elevator projects?

A. The condition of elevator assets for all Company sites are evaluated by outside consultants and subject matter experts. Elevator assets are prioritized for replacement based on the results of these evaluations utilizing a condition assessment score of 1 to 5. Elevators with an assessment score of 3 or below are targeted for modernization or replacement.

Q. How did the Company determine the amount of needed investment in elevator projects for the bridge period and the test year?

A. The total amount of needed investment in elevator projects begins with the five-year historical average spend. Elevator condition assessments are then used to determine how that spend is allocated. While investment in elevator projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. How does the Company identify where furniture replacements are needed?

A. Furniture replacement is determined based on business need. Subject matter experts evaluate business unit requirements and existing furniture. Where the existing furniture does not meet business unit requirements, the furniture is identified for replacement.

Q. How did the Company determine the amount of needed investment in furniture for the bridge period and the test year?

A. The total amount of needed investment in furniture begins with the five-year historical average spend. The needs of the business are then assessed and those assessments are used to determine how that spend is allocated. While investment in furniture may be greater than or less than the five-year historical average spend in a given year, total Asset

Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

New Construction

Q. What capital expenditures are included in the New Construction portfolio category?

A. The New Construction portfolio category includes major projects to build new structures, either on existing Company property or on new properties the Company acquires. In accordance with the Order in Case No. U-21585, the Company in this case will not seek an allowance for its Lansing Service Center Project nor its Hastings Service Center Project in the New Construction category. See Exhibit A-102 (QAG-3). The Company will seek an allowance for these projects when it demonstrates substantial progress on each respective project. In this testimony, the Company will provide information concerning these projects and the status of each respective project.

Q. Does the Company consider environmental impacts when planning for new construction?

A. Yes. New buildings incorporate the United States Green Building Council ("USGBC") standards (see usgbc.org), and the Leadership in Energy and Environmental Design ("LEED") standards (see usgbc.org/leed), with specific emphasis on reduced energy consumption, sustainability, and reduced operating cost.

Q. Do these environmental building standards benefit the Company's customers?

A. Yes. When compared to conventional construction, buildings designed to LEED standards reduce lifetime energy consumption by 30% or more, resulting in reduced operational costs which allow customers to pay less for utility costs. In addition, new buildings require less maintenance and are easier to maintain than an aged structure, resulting in an estimated 5%

cost reduction. Consumers Energy's recently constructed Coldwater Service Center was designed and built to these standards.

Q. Describe the Lansing Service Center project. What is its overall goal?

A. In this project, the Company has purchased land in a new location and will construct a new facility on that property. This facility will allow the Company to retire its existing facility (which will be demolished and retained to address and abate environmental concerns resulting from the operation of a former Manufactured Gas Plant ("MGP") on the site). This new facility will house many employees currently working out of the existing service center. The Company anticipates a portion of these employees will have a hybrid work arrangement in which the employees perform some work tasks at the Lansing Service Center and some work tasks elsewhere including their homes. Employees with a hybrid work arrangement will require collaborative space and open office space in the facility when they are on-site to work with other personnel.

Q. What alternatives to the construction of a new Lansing Service Center did the Company consider?

A. The Company considered the following three alternatives: (1) Do nothing; (2) Renovate the existing Lansing Service Center; (3) Demolish the existing building and construct a new building on site; and (4) Construct a new facility at a new location, with multiple locations considered. The option to construct a new facility at a new location was determined optimal for the reasons noted below.

Q. Why has the Company chosen to build a new Lansing Service Center?

A. As demonstrated in Exhibit A-106 (QAG-7), a Facilities assessment of the existing Lansing Service Center produced a score of 39, placing the existing Lansing Service Center in the

quality designation of "Poor." This information led the Company to rule out a "do nothing" option, and problems with the existing facility's location led the Company to rule out building a new facility on the same site. The existing facility is built on the site of a former MGP, with impacted soil materials underlying the building and other structures. The existing facility is also located within the Grand River flood plain with the building floor elevation three feet below the river's flood stage. Additionally, the existing facility is located in a residential neighborhood and is served by a local road network with schools nearby, resulting in large truck traffic being routed through the residential area, which may be a safety hazard for residents (especially children). Crime in the existing area is also a problem as the site has experienced multiple law enforcement incidents involving the pursuit of armed suspects through the property, including areas within the secured perimeter, and stray shooting incidents. These incidents have resulted in the Company's inability to move vehicles out of the service center (while police officers were pursuing suspects), and a general level of unease regarding the safety and security of employees.

Q. Please elaborate on the reasons the Company decided to build a new Lansing Service Center.

A. As reflected in the scores set forth in Exhibit A-106 (QAG-7), there are several reasons the Company has chosen to relocate the existing Lansing Service Center. These reasons range from the age of the building to customer accessibility. First, the existing service center building was built in 1958. Over time, systems of the building, including major mechanical and electrical systems, even with regular maintenance and replacement, are beyond their useful lives. Currently, these systems require substantial renovations/replacement. Additionally, the existing service center is located in a residentially zoned neighborhood

and due to the location, does not allow Electric Operations to meet customer needs in a timely fashion. Further, the roads (because of the residential zoning) are inadequate for the size of equipment utilized in and out of the service center and there are often children in the vicinity, which creates significant safety concerns. The current site is also located within the floodplain of the Grand River with the finish floor elevation located three feet below the major flooding elevation projected by the Federal Emergency Management Agency. All these considerations negatively impact the Company's ability to dispatch both personnel and equipment to serve customers. Other considerations supporting the decision to construct a new facility, rather than renovate the existing facility, include operating cost reductions, security, and environmental abatement. Because of all of these factors, the Company has decided to build a new Lansing Service Center at a new location.

Q. Can you elaborate further on the security and environmental abatement issues at the Lansing Service Center?

A. Yes. The site has experienced multiple law enforcement incidents. These incidents have resulted in lock-down safety protocol implementation for employees and a resulting general level of unease regarding the safety and security of employees, customers, and others, while on the property and when accessing or leaving the property. Environmental issues arise from the former use of the current Lansing Service Center site as the location of a former MGP regulated under Public Act 451 of 1994, Part 201. This site has historical environmental contamination issues resulting from operation of the MGP, including significant underground impacted soil materials (i.e. coal tar residual). Additionally, the facility contains asbestos insulation for pipe and duct work, asbestos flooring, and has significant areas of lead paint in poor and peeling condition. Given these environmental

issues, upgrades to the facility (e.g. carpet replacement and open space enhancement) cannot be cost effectively completed.

Q. Has the Company engaged in an environmental study for the area selected for the new Lansing Service Center?

A. Yes. The site for the Lansing Service Center includes previous agricultural use; thus, no environmental impacts exist from this previous use. A Phase 1 Environmental investigation has been completed. The site contains wetland areas and the Company is leaving these wetland areas undisturbed. A wetland assessment has also been completed.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Lansing Service Center?

A. The new Lansing Service Center facility is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

Q. The Lansing Service Center project includes the relocation of that facility to a different part of the Lansing metropolitan area. Can you explain what is considered generally when considering relocation of a facility?

A. Yes. As noted earlier, Company facilities are assessed and scored based on multiple criteria (i.e., safety, quality, cost, delivery, and morale) to provide a holistic score that informs the Company of the possible need to make improvements. Facilities with scores falling below the acceptable range are targeted for renovation or replacement. Part of the overall analysis, which is relevant to the Lansing Service Center, is the geographic location of targeted facilities. Geographic locations are analyzed against customer workload distribution within the service territory to determine optimal location for the facility. Facilities that are determined to be mis-located within the customer service territory are

evaluated for relocation to a newly constructed site with the goal of improved customer response. Facilities determined to already be optimally located within the customer service territory are evaluated for renovation or reconstruction on the existing site.

Q. How did the Company determine a new location for the Lansing Service Center?

A. An analysis of customer distribution across the service territory where the Lansing Service Center is located, and potential service center locations within that service territory, determined the optimal area to minimize response times. This analysis is reflected in Exhibit A-106 (QAG-7). Reducing customer response times lowers fuel costs by minimizing the distance Company employees must travel to job sites. Determining the optimal area to minimize response times also maximizes employee efficiency by reducing labor hours required to reach and service customers. The current location of the Lansing Service Center is offset to the north and east of the optimal location, in a residentially zoned neighborhood, and the current location does not provide readily available highway access. The current location of the Lansing Service Center within the service territory results in increased customer response times, higher fuel costs, and reduced employee efficiency due to increased travel times as explained above. The location for the new Lansing Service Center will not only be in a more appropriately zoned area but will also provide improved customer response times.

Q. Has land been acquired for the Lansing Service Center? If so, please identify the location of the land.

A. Yes. Land was acquired for the Lansing Service Center in December 2020, located in Windsor Charter Township, at the southeast corner of the intersection of Canal Road and Billwood Highway, Dimondale, Michigan 48821.

Q. What type of operations departments will work at the new Lansing Service Center as compared to the existing Lansing Service Center?

A. The existing Lansing Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; Gas Engineering & Supply; Generation Operations & Compression; Information Technology ("IT"); Electric Operations; Operations Performance; Shared Services; and People & Culture. The Company anticipates personnel from some (not all) of these operating groups to be housed in the new Lansing Service Center. Because the new facility is being constructed to better serve the Company's customers in the Lansing area, only Company personnel dedicated to servicing these customers will be housed in the new Lansing Service Center.

Q. Approximately how many employees will work at the new Lansing Service Center as compared to the existing Lansing Service Center?

A. Approximately 450 employees are assigned to the existing Lansing Service Center. The Company anticipates the new Lansing Service Center will house approximately 450 employees with some adaptation in their use of the workspace including some employees adopting a hybrid work arrangement, requiring only collaborative space and transient shared office space in the facility when they are on-site to work with other personnel.

Q. What is the status of the Lansing Service Center project at the time of this filing? What work has been completed so far, and what work is still remaining to be done?

A. Land acquisition and rezoning of the parcel in Dimondale has been completed. Design engineering and bidding have been completed and a contract awarded for a municipal water main extension to the project site. The water main extension is fully constructed.

A design-build contract for construction management services has been competitively bid and awarded. Programming of the building is complete and architectural design of the building will be complete before the second quarter of 2025. The Company intends to begin construction of the facility in the third quarter of 2025. See Exhibit A-106 (QAG-7).

Q. How much did the Company invest in the Lansing Service Center project in the 2024 historical year in this case?

A. In the 2024 historical year in this case, the Company invested $2,170,000 in this project. See Exhibit A-102 (QAG-3).

Q. Please describe the Hastings Service Center project. What is its overall goal?

A. The Company is planning to construct a new Hastings Service Center at the existing service center location to include an adjacent property the Company is negotiating to purchase from the adjacent landowner. This new facility will house most employees currently working at the existing service center. A portion of the employees currently working at the existing service center will have a hybrid work arrangement and will require only collaborative space and transient shared office space in the facility when they are on-site to work with other personnel.

Q. What alternatives to the construction of a new Hastings Service Center did the Company consider?

A. The Company considered four alternatives: (1) Do nothing; (2) Renovate the existing Hastings Service Center; (3) Demolish the existing building and construct a new building on site; and (4) Construct a new facility at a new site. The options to either demolish the existing building and construct a new building on site or demolish the existing building

and construct a new building at a larger site were identified as optimal depending on availability of suitable land.

Q. Why has the Company chosen to construct a new Hastings Service Center facility?

A. As demonstrated in Exhibit A-106 (QAG-7), a Facilities assessment of the existing Hastings Service Center produced a score of 41. As discussed above, because this score falls below a score of 48, it was targeted for replacement, and the "do nothing" option was ruled out. For the same reason that the Lansing Service Center was targeted for replacement, including aging infrastructure, which is beyond useful life, the Hastings Service Center was determined to need replacement. The current site is fully developed and is no longer sufficient to support ongoing utility operations as the site lacks adequate space for both safe vehicle maneuvering and utility construction material storage. In addition, the existing building envelope does not comply with current energy code requirements. The Facilities organization, therefore, ruled out the renovation option for the Hastings Service Center. The existing Hastings Service Center site is located within an industrialized area with access to major roads and highways. The Company determined that the facility is currently in an optimal location to service customers (see Exhibit A-106 (QAG-7)). Therefore, with the acquisition of appropriate adjacent parcels, the Hastings Service Center has been targeted for replacement on the existing site in lieu of relocation. Other considerations supporting the decision to replace the existing site include environmental abatement.

Q. Can you further elaborate on how these alternatives were compared?

A. The Company originally sought to construct a new facility on the existing property. Construction of the new Hastings Service Center on the existing property was predicated

on reaching agreement with the adjacent landowner to transfer a portion of their property to Consumers Energy, which would increase the available site area for development and provide enough space for the new facility. Agreement for a property transfer with an adjacent landowner was initially not reached. The properties on the west and east are fully developed. The Company then entered negotiations with the Barry County Road Commission (owner of the adjacent parcel to the south). The Barry County Road Commission approved the Company's conceptual plan for development of this parcel. The Company completed acquisition of the parcel in March 2025 which will allow for expansion of the existing Hastings site and construction of the new facility.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Hastings Service Center?

A. The proposed new Hastings Service Center facility is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

Q. Will this building be larger or smaller than the existing Hastings Service Center?

A. The conceptual site plan for the new service center is shown in Exhibit A-106 (QAG-7). The original projected building area based on conceptual data assembled is larger than the existing Hastings Service Center by 11,183 square feet. The new facility is designed with a larger footprint to address multiple deficiencies at the existing facility that negatively impact electric operations including insufficient space for crew rooms, parts and material storage, welding operations, and automotive tools and repairs. Even at 23,500 square feet, however, the projected building area of the new Hastings Service Center, based on conceptual data, is smaller than many of the Company's Service Centers.

Q. What type of operations departments will work at the new Hastings Service Center as compared to the existing Hastings Service Center?

A. The existing Hastings Service Center houses the following operations: Gas Operations; Electric Operations; Planning & Scheduling, and Shared Services. The Company anticipates the new Hastings Service Center will house many of these same operations.

Q. Approximately how many employees will work at the new Hastings Service Center as compared to the existing Hastings Service Center?

A. The existing Hastings Service Center houses approximately 50 employees. The Company anticipates the New Hastings Service Center will house a comparable number of employees.

Q. What is the status of the construction of the Hastings Service Center at the time of this filing? What work has been completed so far?

A. The Barry County Road Commission (owner of the adjacent parcel to the south) has approved the Company's conceptual plan for development of the parcel. A Phase 1 Environmental Study, a Phase 2 Environmental Study, and a Baseline Environmental Assessment have been completed. The adjacent parcel to the south was acquired in March 2025 and programming design for the new facility has commenced.

Q. How much did the Company invest in the Hastings Service Center project in the historical year in this case?

A. In the 2024 historical year in this case, the Company invested $114,000 in this project for survey and related real estate work done on the site. See Exhibit A-102 (QAG-3).

Renovations

Q. What capital expenditures are included in the Renovations portfolio category?

A. The Renovations portfolio category includes major modifications to the interior and/or exterior of existing facilities (e.g. adding a garage to a building). As shown in Exhibit A-102 (QAG-3), the Company is projecting to spend $15,603,000 on Renovations in the bridge period and $15,855,000 on Renovations in the test year.

Q. Has the Company identified projects in the Renovations portfolio category?

A. Yes. As shown in Exhibit A-102 (QAG-3), the Company has identified the following Renovations projects:

- Kalamazoo Service Center
- Control/Dispatch Center – Grand Rapids
- Control/Dispatch Center - Parnall
- South Monroe Interior Renovation
- Electric Vehicle Infrastructure

In accordance with the Commission Order in Case No. U-21585, the Company in this case will not seek an allowance for its Kalamazoo Service Center Project in the Renovations category. See Exhibit A-102 (QAG-3). The Company will seek an allowance for this project when it demonstrates substantial progress on the project. In this testimony, the Company will provide information concerning this project and its status.

Q. Describe the Kalamazoo Service Center project. What are its overall goals?

A. In this project, the Company is renovating the existing Kalamazoo Service Center. The Company is remediating asbestos concerns, workspace concerns, and problems with aging building systems at the existing facility upon completion of this renovation. The

renovations of this facility entail adding insulation to exterior walls, installation of new exterior doors and windows, new roofing membrane and roof insulation, new interior finishes, new furnishings, new plumbing fixtures and fittings, new HVAC equipment and ductwork, and new energy efficient lighting systems.

Q. What alternatives to the renovation of the Kalamazoo Service Center did the Company consider?

A. The Company considered the following three alternatives: (1) Do nothing; (2) Renovate the existing Kalamazoo Service Center; and (3) Demolish the existing building and construct a new building on site. The option to renovate was identified as optimal.

Q. How did the Company decide to renovate the existing service center?

A. The Company originally planned to construct a new facility on the existing property, as Company witness Scott J. Bartholomew testified in his direct testimony in Case No. U-20963. The Company subsequently reevaluated its plans to ensure the renovated Kalamazoo Service Center is constructed in a manner that optimizes use of capital. In Case No. U-20963, the Company's projected total cost for the renovated Kalamazoo Service Center was $52 million. The Company's projected total cost for the renovated Kalamazoo Service Center is now $35 million, an approximate 33% reduction in cost. The Company determined that a renovation would meet its workforce needs and provide better value for customers by minimizing the scope of architectural work required to achieve needed improvements in the facility. A renovation of the existing Kalamazoo Service Center will maximize utilization of the building's existing space, while controlling capital costs and minimizing disruptions to the Company's operations. Specifically, a renovation will minimize disruptions both to areas that house the Company's operating crews and to areas

where the equipment and vehicles that crews use to service customers are maintained and serviced. Other considerations supporting the decision to renovate the existing facility include the fact that the Kalamazoo Service Center is already optimally located for responding timely to the Company's customers.

Q. Why is doing nothing not a viable option at this location?

A. As demonstrated in Exhibit A-106 (QAG-7), a Facilities assessment of the existing Kalamazoo Service Center produced a score of 46. Since this assessment was conducted, additional asbestos issues have been identified at this site (i.e. spray applied fireproofing, pipe wrap, floor tiles, etc.). All employees at this site were moved to the second floor of the building due to air quality issues rooted in the growth of mold and related asbestos concerns on the first floor. This limited space is inadequate for the Company's Electric and Gas Operations employees to operate. As discussed above, because an assessment score of 46 falls below a score of 48, the Kalamazoo Service Center was originally targeted for replacement. In addition to its environmental concerns, the existing Kalamazoo Service Center was constructed in 1965, and its continuing use was determined inadequate due to aging infrastructure. Most of the existing systems throughout the facility are over 50 years old and beyond their useful lives. The space requirements of the existing workforce have changed as more personnel adopt a hybrid work arrangement requiring only collaborative workspace and open office space when they are in the office working collaboratively with others. Finally, the existing Kalamazoo Service Center is optimally located for responding timely to the Company's customers and, therefore, remaining at the current location best supports the Company's intent to provide timely service to its customers in the Kalamazoo area.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the renovated Kalamazoo Service Center?

A. The renovated Kalamazoo Service Center is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

Q. What is the status of the renovation of the Kalamazoo Service Center at the time of this filing?

A. The Company has bid and awarded a contract for construction management services and a contract for architectural and engineering design services. Architectural and engineering design work on the project is complete and renovation construction is underway. See Exhibit A-106 (QAG-7).

Q. How much did the Company invest in the Kalamazoo Service Center project during the historical year of this case?

A. The Company invested $4,551,000 in this project during the 2024 historical year for engineering and construction associated with renovation of the facility. See Exhibit A-102 (QAG-3).

Q. Is the projected size of the renovated Kalamazoo Service Center larger or smaller than the existing Kalamazoo Service Center?

A. The size of the renovated Kalamazoo Service Center is not projected to vary significantly from the size of the existing Kalamazoo Service Center because there is no anticipated change in the overall footprint of the facility.

Q. What type of operations departments will work at the renovated Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?

A. The existing Kalamazoo Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; Information Technology (IT); Electric Operations; Shared Services; and Public Affairs. The Company anticipates personnel from some (not all) of these operating groups to be housed in the renovated Kalamazoo Service Center.

Q. Approximately how many employees will work at the renovated Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?

A. Approximately 250 employees are assigned to the existing Kalamazoo Service Center. The Company anticipates the renovated Kalamazoo Service Center will house the majority (not all) of these employees with some employees adopting a hybrid work arrangement and requiring only collaborative space and transient shared office space in the facility when they are on-site to work with other personnel.

Q. Please describe the Control/Dispatch Center Consolidation - Parnall Project and Control/Dispatch Center Consolidation – Grand Rapids Project. What are the overall goals of these projects?

A. A complete description of both Control/Dispatch Center Consolidation Projects and their overall goals are outlined in the testimony of Company witness Andrew R. Snider. This testimony is tailored very narrowly to a discussion of the building renovations that support the Control/Dispatch Center Consolidation Project – Grand Rapids and the Control/Dispatch Center Consolidation Project – Parnall which together comprise the

Control/Dispatch Center Consolidation Project discussed in Company witness Snider's testimony.

Q. What benefits will the renovations constructed pursuant to the Control/Dispatch Consolidation projects provide to customers?

A. The benefits to customers of the Control/Dispatch Center Consolidation Project renovations are outlined in the testimony of Company witness Snider.

Q. How much does the Company project to invest in both Control/Dispatch Center Consolidation renovations in the bridge period and test year in this case?

A. As shown in Exhibit A-102 (QAG-3), the Company is projecting to invest a total of $10,746,000 in Control/Dispatch Center Consolidation Project renovations in the bridge period and a total of $15,497,000 in Control/Dispatch Center Consolidation Project renovations in the test year.

Q. How have these projected costs been derived?

A. Cost estimates were developed utilizing the conceptual plan and historical cost data from many similar projects.

Q. What is the status of the Control/Dispatch Center Consolidation Project renovations at the time of this filing?

A. The Control/Dispatch Center Consolidation Project – Grand Rapids and the Control/Dispatch Center Consolidation Project – Parnall are both in design. See Exhibit A-106 (QAG-7).

Q. Describe the South Monroe Service Center Interior Renovation Project. What is its overall goal?

A. The purpose of this project is to acquire design and engineering services needed to remodel a portion of the Company's South Monroe Service Center interior. This remodel will provide adequate meeting space for Company crews. The remodel will also bring the facility into compliance with multiple code requirements including but not limited to the Americans with Disabilities Act ("ADA") access, the number of restroom fixtures required per building occupant, and ventilation required in the building's indoor parking area ("IPA"). The project will include development of a building addition needed to house utility construction equipment and maintenance materials such as cable ties, insulators, cable splices, and switches. The size of the existing South Monroe Service Center is no longer adequate to support operational needs. The workload assigned to the South Monroe Service Center has increased and the number of Company crews operating from the building has increased commensurately. This, in turn, has driven an increase in the amount of material necessary to support work at the site and an increase in the amount of space required in the building to support operational needs.

Q. What alternatives did the Company consider for this project?

A. The Company considered the following alternatives: (1) Do nothing; (2) perform an interior renovation only; (3) perform an interior renovation and construct a building addition; or (4) perform an interior renovation and acquire an adjacent building in lieu of constructing a building addition. Doing nothing is not a suitable option because the existing building is no longer suitable to support operational needs and must be brought into compliance with several code requirements. An interior renovation only (the second

alternative) would provide adequate space for crew meetings and bring the building into compliance with several code requirements but is ultimately not suitable because it would not address the site's need for additional storage space. An interior renovation coupled with a building addition (the third alternative) and an interior renovation coupled with acquiring an adjacent building (the fourth alternative) would provide adequate space for crew meetings, will bring the building into compliance with minimum code requirements, and will meet the site's need for additional storage space. The fourth alternative was deemed optimal because the cost of acquiring an adjacent building is less than the cost of building a comparable addition (the third alternative).

Q. Why did the Company choose to perform this renovation?

A. As noted, the South Monroe Service Center is not adequate to support the site's growing workload and is currently out of compliance with several code requirements.

Q. What benefits will this building provide for customers?

A. The increased workload at the South Monroe Service Center is driven by an increase in the pace of system reliability work the Company is performing. The Company's workforce assigned to the South Monroe Service Center requires adequate storage space for materials, vehicles, equipment, and crew room space to perform system reliability work. The Company's customers in the South Monroe area directly benefit from fewer, shorter outages that result from a more reliable and resilient electric distribution system in the area.

Q. How much does the Company project to invest in the South Monroe Service Center Interior Renovation project in the bridge period and test year in this case?

A. As shown in Exhibit A-102 (QAG-3), the Company is projecting to invest $4,186,000 in the South Monroe Service Center Interior Renovation Project in the bridge period and $86,000 in the test year.

Q. How have these projected costs been derived?

A. Outside consultants and contractors have been engaged to develop and prepare a design program and construction schedule for the South Monroe Interior Renovation Project. These firms have evaluated the design program and construction schedule to develop project cost estimates.

Q. What is the status of the construction of the South Monroe Service Center renovation project at the time of this filing?

A. Architectural design work is in progress and the Company has acquired a building from an adjacent property owner that will be used for material and equipment storage. See Exhibit A-106 (QAG-7).

Q. Has the Company invested any capital in the South Monroe Service Center renovation project so far?

A. $908,000 has been invested in the South Monroe Service Center Interior Renovation Project for architectural design services and acquisition of an adjacent building. See Exhibit A-102 (QAG-3).

Q. Please describe the Electric Vehicle Charging Infrastructure project. What are its overall goals?

A. As outlined in my direct testimony, the Company plans to electrify portions of its vehicle fleet by purchasing EVs for Company use. The Company is currently acquiring EVs. To ensure these EVs are available for Company crews to use in serving customers, the Company must construct adequate charging infrastructure at sites where these vehicles will be maintained.

Q. How much capital is the Company projecting to invest in the Electric Vehicle Charging Infrastructure project in the bridge period and test year in this case and for what purpose?

A. As shown in Exhibit A-102 (QAG-3), the Company is projecting to invest $671,000 in the Electric Vehicle Charging Infrastructure project in the bridge period and $272,000 in the test year. The purpose of this investment is to provide the electric infrastructure upgrades and charging station installations required to support EVs purchased in the bridge period and test year as outlined in my direct testimony.

Q. At what buildings will EV charging infrastructure be installed during the bridge period and test years of this case?

A. The planned headquarter locations at which EV charging infrastructure will be installed include Jackson, Royal Oak, Lansing, Bay City, Battle Creek, and Adrian.

Q. How were these costs determined?

A. Cost estimates were developed for electric infrastructure upgrades and charging station installations required to support EVs purchased in the bridge period and test year utilizing historical cost data from similar previous projects.

O&M Spending Overview

Q. What O&M expenses are included in "Facilities" in Exhibit A-101 (QAG-2), line 1?

A. Facilities work includes items such as maintenance and repair of HVAC systems, miscellaneous building repairs, yard maintenance and snow removal, and daily cleaning or other major scheduled cleaning projects such as windows and carpeting. The Company maintains data on maintenance history in its buildings. This data, in conjunction with historical spend, is used to forecast projected Facilities O&M expense growth at or below the rate of historical plus the current inflation factor year over year.

Q. What O&M expenses are included in "Real Estate" in Exhibit A-101 (QAG-2), line 2?

A. Real estate services includes a variety of real estate asset management functions to ensure system integrity and safeguarding of the public. This includes management of all land-related uses of easements and rights of way, including encroachments, third-party requests for use of Company property, landowner requests for modification of easement rights or approval of permission to construct within an easement, as well as management of all corporate facility leases. The group also responds to all requests to sell property or grant easements, leases, or licenses to third parties. Included in real estate services is the records management function that is responsible for maintenance of a land inventory and Geographic Information System mapping for property ownership and rights of way. The Company reviews its needs for real estate services annually. This information, in conjunction with historical spend, is used to forecast projected Real Estate O&M expense growth at or below the rate of historical plus the current inflation factor year over year.

FLEET SERVICES FUNCTION AND RESPONSIBILITIES

Q. What functions compose the Fleet Services organization?

A. The Fleet Services organization consists of three departments which collaboratively work together to provide value to Electric Operations in serving customers. The three departments include Fleet Maintenance Operations, Fleet Acquisition, and Shared Services Governance Performance and Technology.

Q. Are you addressing all support organizations related to Electric Operations Support in your direct testimony and exhibits?

A. Yes.

Q. Please explain the responsibilities of Fleet Maintenance Operations.

A. Fleet Maintenance Operations is responsible for maintaining a safe, cost effective, and reliable fleet. This is accomplished through preventative maintenance, regulatory inspections, parts inventory management, and maintenance scheduling across 36 garage locations with approximately 110 mechanics. Maintenance Operations also oversees mechanic contractor crews for preventative maintenance and repairs performed in the field.

Q. Please explain the responsibilities of Fleet Acquisition.

A. Fleet Acquisition executes all functions related to the acquisition and disposition of Company-owned and rented vehicles and related equipment. This includes management of the Fleet capital purchase plan, vehicle specification design, licensing/title, registration, and asset retirement.

Q. Please explain the responsibilities of Shared Services Governance Performance and Technology department.

A. Governance Performance and Technology provides fleet with support of data integrity, Telematics data management (software installed in vehicles to provide information such as location, speed, fuel consumption, etc.), departmental metric visual management, process automation, oversight of waste elimination initiatives, and evaluates benchmarking and data analysis provided to the Company. This team is also responsible for meeting all regulatory and compliance requirements with the American National Standards Institute, Department of Transportation, Michigan Motor Vehicle Code, and Federal Motor Carrier Safety Administration. Additional responsibilities include Fleet Operations Policies and Procedures, regulatory and technical support, and tooling for fleet mechanics and the Company's EV strategy. The department also provides oversight for quality inspection audits and safety requirements related to regulatory compliance.

Q. Please explain the Company's overall fleet structure.

A. The Company's fleet includes approximately 7,207 owned, leased, and rented units across 36 locations. These units include light duty vehicles (approximately 2,800 units), medium and heavy-duty trucks (approximately 1,500 units), various types of equipment (approximately 1,400 units), and trailers (approximately 1,900 units). Internally, the Company categorizes its fleet into several specifications ("spec(s)"), each of which is a given type, model, and description of a vehicle. Each spec has a defined intended use, acquisition cost, operating cost, and expected life in years and mileage.

Q. How is the Company's fleet divided between the electric and natural gas businesses?

A. The Company divides its fleet between the electric and natural gas businesses by determining which business unit at a given location is using each particular vehicle. The needs of the business require the deployment of dedicated teams to safely complete work utilizing specific tools and processes – this extends to the vehicle supporting said work. These vehicles are ordered and upfitted to support specific work and are, therefore, specialized for the work they perform; however, the Company does seek ways that units can be shared across the business when possible. The fleet requirements for the location will vary based on the service provided to the customer (electric, gas, or both), crew counts, and region. Additionally, some Company fleet units serve both electric and gas functions and are referred to as "common" units, which are utilized by support organizations, such as Facilities, Fleet, and Supply Chain. Overall, the Company's fleet is 40% electric, 50% gas, and 10% common by number of vehicles.

Q. What is the purpose of Fleet Services as it relates to the Company's electric business?

A. Specific to the Company's electric business, Fleet Services' purpose is to provide vehicles and equipment that enable Electric Operations to serve customers with safe, reliable, and affordable electric service. This is accomplished by ensuring that the Company's Fleet assets are available to execute the work plan and respond to emergencies in the most efficient, cost-effective, and safe manner when required.

Q. Does the Company's fleet incur both capital and O&M costs?

A. The Company makes direct capital investments in its fleet as provided in Exhibit A-12 (QAG-1), Schedule B-5.6, page 4. The Company also incurs other costs related to its fleet

that are treated as "fleet responsibility" dollars, which in this case are presented in Exhibit A-103 (QAG-4).

Q. What are fleet responsibility dollars?

A. In addition to direct capital expenditures for fleet vehicles, tools, and other equipment, the Company also incurs other costs related to its fleet that are treated as "fleet responsibility" dollars. The Company does not have specific Fleet O&M expenses.

Fleet operating costs are reported in responsibility dollars. Each fleet unit has defined work assignments that determine which functional areas are allocated the associated responsibility dollars for the unit. Fleet responsibility costs are allocated to both capital and O&M expenses based on the work assignment performed.

Q. Please explain how fleet responsibility dollars are allocated to both capital and O&M.

A. The process for allocating fleet responsibility dollars is a multi-step process. The first step in the process is that costs associated with each fleet vehicle or piece of equipment are charged to an internal order. Each fleet vehicle/equipment has its own internal order that collects costs like fuel and maintenance, which is assigned to a department/responsibility area.

The next step is that the costs from the internal orders are moved to separate fleet clearing accounts for each department/responsibility area. The final step in the process is the allocation of the costs from the fleet clearing accounts. The costs in each clearing account are allocated to work orders or cost centers based on the labor charges for that respective department/responsibility area. Additionally, the fleet costs to be allocated are separated between labor and non-labor fleet loading**.**

Q. Can the Company identify to which budget line items, in various parts of the business responsibility dollars, are allocated and ultimately settled?

A. No. Fleet responsibility dollars are assigned to multiple work orders and ultimately settle to multiple cost centers making it difficult to determine with reasonable accuracy the allocation of fleet responsibility costs to specific line items in various parts of the business.

FLEET REPLACEMENT PLANNING PROCESS

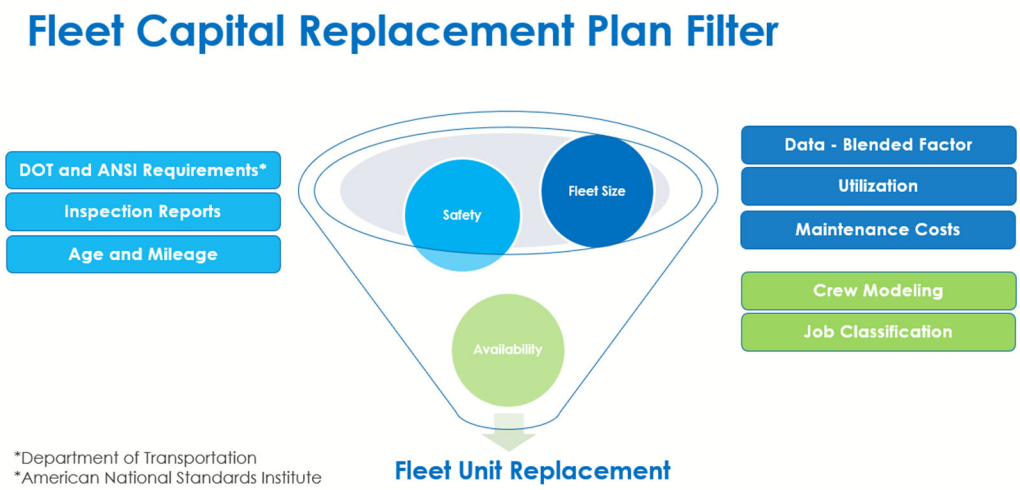
Q. What is the Company's overall Fleet Replacement Planning Process as it is being presented in this case?

A. As previously presented in Electric Rate Case Nos. U-20963, U-21224, U-21389, and U-21585, and Gas Rate Case Nos. U-21148, U-21308, U-21490, and U-21806, the Company develops its Fleet Vehicle Capital Replacement Plan using the Fleet Replacement Planning Process, which is a process that incorporates three phases. In the first phase, the Company identifies vehicles that are at or near the end of their expected life and are eligible for replacement, using a tool called the Blended Factor that is described in more detail below. Next, in the second phase, the list of vehicles identified by Blended Factor Analysis for potential replacement is further developed by certain data tools, described below, particularly by fleet cost data, followed by crewing data, and, lastly, fleet utilization data. In this second phase, the Company's fleet leadership also works with Operations leadership and personnel in the field, which includes operators and mechanics, to identify which specific units should be replaced, incorporating qualitative inputs like maintenance reports and local area work needs. This second phase allows for further evaluation of the vehicles identified in the first phase to better determine which vehicles should be replaced. Thereafter, in the third phase, the list of vehicles identified for

retirement is finalized based on the evaluations performed in the first two phases, and the ordering process begins. If an existing contract is in place, orders are placed immediately with the manufacturer or vendor. For vehicles not covered by an existing contract, detailed specifications are written and requests for proposals are sent to vendors. Once bids are received, they are evaluated and awarded based on cost, product support, and quality.

Q. Please further explain how the Company establishes its Fleet Replacement Planning Process.

A. The Company strives to replace assets at the optimal moment in the vehicle's service life by incorporating several factors in the decision-making process, particularly within phases 1 and 2. In doing so, the Company uses data gathered for each spec that is documented, monitored, and corroborated with detailed in-person inspections. Data is generated by the fleet through Telematics, including utilization rates, fleet age, and detailed inspections as a basis for determining future fleet purchases of specific capability and utility. The Company's process for compiling and analyzing qualitative and quantitative inputs to develop its Fleet Vehicle Capital Replacement Plan is illustrated by the "filter" shown below.



Q. Please explain how the Fleet Capital Replacement Plan Filter works.

A. When the Company goes through its Fleet Replacement Planning Process, specifically within phases 1 and 2, certain data – such as the Blended Factor, utilization, operating cost, and crewing needs – is analyzed to determine if a given vehicle needs to be replaced. During the Fleet Replacement Planning Process, other qualitative inputs like vehicle inspection reports and the assessments by field employees provide further insight on replacement needs. The result of this process, specifically following the first and second phase, is a list of fleet units to be replaced.

Q. Can you describe, in further detail, the Blended Factor used in phase 1 and the Fleet Cost Tool, Crewing Model Tool, and Fleet Utilization Tool used in phase 2?

A. Yes. These are each described in the following sections.

A. <u>Blended Factor</u>

Q. Please further explain the Blended Factor.

A. The first step in the Company's process for establishing its Fleet Vehicle Capital Replacement Plan is informed by the Blended Factor. As previously mentioned, the Blended Factor takes age, usage, and mileage into consideration and establishes a replacement priority for units that are more economical to replace than continuing to maintain. The Blended Factor for any vehicle is calculated as shown in the illustrative example below:

Blended Factor Calculation

$$\text{Blended Factor Rating} = \left(\frac{[\text{Age Factor} + \text{Usage Factor}]}{2}\right)$$

$$\text{Age Factor} = \left(\frac{\text{Actual Age in Months}}{\text{Expected Life in Months}}\right) - 1$$

Example: $\left(\frac{102}{84}\right) - 1 = .21$

$$\text{Usage Factor} = \left(\frac{\text{Estimated Mileage}}{\text{Expected Life Mileage}}\right) - 1$$

Example: $\left(\frac{223{,}180}{150{,}000}\right) - 1 = .488$

Blended Factor Example: $\left(\frac{[.21 + .488]}{2}\right) = .349$

Equipment and engine operation hour calculation: 1 hour = 25 miles

For equipment that does not have mileage (no odometer), the Blended Factor calculates usage from the engine hours. For medium and heavy-duty vehicles, the Blended Factor calculation also uses total engine hours, assuming that one hour of engine operation is equivalent to 25 miles of travel. Using this calculation, a Blended Factor result greater than 0.00% indicates that a vehicle is at or past its expected life and is therefore eligible for consideration for replacement. This indicator does not mean that a vehicle with a result greater than 0.00% is automatically selected for replacement; it is instead a *starting point* each year for the Company to use as a foundation in the selection of vehicles for replacement.

Q. Why is it important for the Company to consider the expected life in months and expected life in mileage for each of the respective specs?

A. The Blended Factor formula incorporates two key indicators of how a vehicle reaches the end of its expected life: (1) how old a vehicle is and (2) either how many miles it has traveled or total hours of operation. Expected life in months considers manufacturer inputs,

reliability, operating conditions, and operating cost to determine the duration the Company expects a vehicle to operate safely and cost effectively. Expected life in mileage or hours is also based on similar considerations as an indicator of wear and tear. The Company makes these evaluations to set a foundational benchmark to assess potentially replaceable vehicles. The fleet has a diverse range of specs for specific operational needs, and not all specs have the same expected life. Even within the same spec, individual units can vary in condition depending on utilization and wear. Managing each spec to its appropriate expected life ensures that the Company always has the right type of vehicle available to serve the needs of customers in the safest, most reliable, and most efficient manner possible, while minimizing costs.

Q. Why is the use of the Blended Factor appropriate?

A. The Blended Factor is an internal data-based algorithm that incorporates unit age, utilization (in mileage or hours), and expected life, allowing the Company to prioritize, plan, and target specific vehicle(s) for replacement. As a key feature of the *first phase* of the replacement process, the vehicles denoted by the Blended Factor to be approaching the end of their expected life provide the basis for planning phases ahead. This process is critical to ensure that the Company can order a timely unit replacement, especially given the supply chain challenges that have emerged in the last three years. While there has been some improvement in the expected delivery dates for some products, planning around potential delivery delays and availability is still a concern as demand for new medium and heavy-duty equipment remains high. By using the Blended Factor, the Company can strategize future spending for replacement units for specific years by consulting with

suppliers on current and future availability, thereby preparing the Company to order units given current lead times to receive a unit once an order is placed.

Q. What conclusions do you draw regarding the Blended Factor?

A. The Blended Factor provides an objective standard that uses clear internal fleet data to identify units for potential replacement and adds a level of predictability regarding which units will need to be replaced to improve the cost-effectiveness of the replacement process. Based on the above Blended Factor calculations, it is indicated that out of 7,207 units currently in the fleet, there are approximately 1,903 units greater than 0.00%.

B. Fleet Cost Tool

Q. Please explain the Company's fleet cost tool.

A. As part of the second phase in its Fleet Replacement Planning Process, the Company is utilizing the fleet cost tool, incorporating data analytical tools to support near- and long-term cost-effective vehicle purchase plans. These analytical tools include tracking vehicles by spec and the average age of each spec, fleet O&M costs, and geographical location. Additionally, the fleet cost tool provides at-a-glance total and average per-vehicle operating costs for each spec from various perspectives, including operating costs per mile, by age, and by specific vehicle. These tools provide data indicating vehicle count and average age, broken out by spec. The purpose of these tools is to provide overall cost status summaries of the fleet, as well as a platform to perform more detailed cost analyses of individual vehicles. The following are descriptions of several tools the Company has developed.

Q. What are these tools that the Company has developed to support fleet cost analyses?

A. For an overall summarization of fleet age and operating costs, the Company has developed "Unit Age and Operating Cost" and "Unit Count and Average Age" tools to provide information regarding fleet operating costs correlated with age. Operating costs include maintenance, fuel, and repairs. This information can be filtered by vehicle year and spec and can assist in identifying trends that will enable cost forecasting to support future purchasing decisions.

Q. What are additional analytical tools related to fleet cost?

A. The Spec Detail Information Analysis identifies equipment count by spec and is designed to highlight yearly fleet composition by spec, which helps identify trends and how the fleet's makeup and size changes over time.

Q. Are there any other analytical tools that are part of the fleet cost tool?

A. The Age and Cost Spec Detail Analysis is designed to provide detailed cost information for a specific unit, including total operating cost, as well as average costs over time for specific specs. In this analysis, the Company evaluates equipment count, total operating cost, average unit operating cost, median unit operating cost, and average unit age. Finally, a Location Summary Analysis displays a particular territory, city, spec, equipment count, and total operating cost for vehicles distributed throughout the Company's service area. Equipment Count by location is displayed on a map with circle size indicating high/low equipment counts and color indicating zone. Average Unit Age and Total Operating Costs are summarized in cards at the top of the page. This page allows the user to filter by Year, Usage Indicator, Rental Status, and Specification. The purpose of this tool is to allow the user to use the filters to summarize equipment count, cost, and age by location.

Q. Why are these fleet cost analytical tools appropriate for the Company to use?

A. Using the Company's own data, the information these tools provide is used to help the Company plan the cost-efficient replacement and acquisition of new vehicles. The Fleet Cost Tool data provides information from several perspectives that helps narrow the pool of vehicles identified by the Blended Factor for replacement. For example, the Blended Factor may identify many units within any given spec that are at or near the end of their expected life, but a further examination using this tool can help inform how the unit is performing in relation to other identical spec vehicles in the fleet from a cost perspective. If the unit has become uneconomical to operate compared to other vehicles in the same spec, it may be best to replace that vehicle for a more cost-effective solution sooner rather than later. Conversely, a vehicle that has reached the Blended Factor end of expected life may still have years of economical service possible based on operating cost reported by these tools. This fleet cost tool also allows the Company's fleet management to understand how fleet costs have changed year-over-year, including the ability to examine costs of specific units to help inform if they are good candidates for replacement. The tool is intended to provide an overview of past fleet metrics, and helps to identify relationships between unit age, mileage, and operating costs. It also shows fleet age by spec which can be helpful when multiple units of the same spec were purchased in the same year. This is valuable information to consider when prioritizing the most appropriate vehicles to replace at any given point for the benefit of customers.

Q. What has the Company learned to date from using its fleet cost tool?

A. The fleet cost tool has allowed the Company to make informed decisions while reviewing units identified for replacement. This tool provides the Company with an at-a-glance total

of overall costs of a particular unit. As the fleet team strategizes how and where to replace vehicles, the cost tool assists in framing how to best benefit the customer in the decision-making process.

As noted, the Blended Factor calculation is a starting point in the decision-making process, with the expectation that the list can be modified as further analysis proceeds. The cost tool facilitates a review of repairs and improvement costs associated with each vehicle that can extend its service life. For example, feedback sought and received from field leaders on the overall condition and serviceability of a truck can show that it should be kept in service instead of being replaced. This includes investments like engine or transmission rebuilds, or body rust repairs. The fleet cost tool quickly identifies which units require closer scrutiny when making purchasing decisions. This benefits the customer in that the Company gets as much service life out of units as is economically prudent.

C. Crewing Model Tool

Q. Please explain the Company's crewing model and crewing model tool.

A. As part of the second phase of its Fleet Replacement Planning Process, the Company's crewing model is used to calculate how many vehicles are needed based on the size of the workforce. This model incorporates all electric department vehicles and details about which employees are assigned to operate these vehicles. The electric departments include Customer Field Services, Electric Meter Operations, Low Voltage Distribution ("LVD"), and Substation Maintenance. These departments operate the following types of vehicles: bucket trucks, digger derricks, service buckets, pickup trucks, and other support vehicles. The crewing model tool illustrates how many vehicles are needed and how many vehicles are available, giving visibility to gaps.

Q. What information does the tool show?

A. The tool lists Company locations and, for each location, shows the number of units at that location by workgroup, breaking down the number of employees and the number of different types of units located there. Based on this information, the tool provides the gap between the actual number of vehicles at the location and the number of vehicles needed.

Q. How was this crewing model developed?

A. The Company's Electric Operations Department's workforce size and crewing influences the number and types of vehicles needed to serve customers. Crewing is determined by the work required and influenced by safety and policy procedures related to the work performed. In the crewing model, the Company uses standard crewing of the following truck-to-employee ratios:

- Electric LVD crewing consists of one Line Worker in Charge ("LWIC"), one Journeyman Line Worker ("JLW"), and one Apprentice to make one crew. Each crew is assigned a bucket truck and a support vehicle. The support vehicle could be a digger derrick or a pickup. The current crewing model calculates vehicle needs according to the following ratios:

Vehicle Type	Model Ratio
Bucket Truck	1:1 LWIC to Bucket Truck
Digger Derrick	2:1 LWIC to Digger Derrick
Pickup	2:1 LWIC to Crew Vehicle
Trencher	4:1 LWIC to Trencher

- Employees in Electric Meter Operations, Customer Field Services, Electric Field Lab, and Substation Maintenance usually operate as single workers, rather than in a crew, meaning they have a 1:1 vehicle ratio.

Q. Why is this crewing model appropriate for the Company to use?

A. The crewing model is based on industry best practices and Occupational Safety and Health Administration ("OSHA") requirements.[1] To provide a safe, reliable, and cost-effective

[1] 1926.960 - Working on or near exposed energized parts. | Occupational Safety and Health Administration (osha.gov): https://www.osha.gov/laws-regs/regulations/standardnumber/1926/1926.960

fleet, it is important that the Company's fleet be adequate in size to complete the established work plan, work safely, and adhere to OSHA requirements.

Q. What conclusions can you draw from the data shown in the crewing model tool?

A. The model shows that the quantity of production units (bucket trucks, digger derricks, and service bucket trucks) currently in the Company's fleet will continue to be evaluated based on established work plans and employees needed to perform the work (more information on how utilization data is calculated is provided in the next section of this testimony). The model can help identify surplus or deficiency of assets in each specific area and units that are down for repairs or regular maintenance. This visibility allows the Company to reallocate surplus assets to areas with deficiencies to ensure each area is adequately supplied based on the model. Backup vehicles must be ready to meet the needs of the crews as daily schedules develop, meaning that some additional vehicles may be needed on short notice. The Crewing Model allows for backup vehicle availability for such circumstances to reduce the risk of gaps between crews and vehicles needed in the field.

The crewing model assumes the Company will onboard new workers or add replacement workers consistently and in a timely manner as work plans develop to drive the need for workers and as attrition rates affect the workforce. However, the Company does not always receive new vehicles at the same time new workers are onboarded. For this reason, it is possible that new vehicles will be received and paid for before workers are ready to use them, but those vehicles *will* be put into use once the planned hiring is complete. Utilization rates for vehicles may at times reflect this reality.

Q. What has the Company learned to date from using its Crewing Model?

A. The Crewing Model offers the ability to find gaps in available units, and much like a checklist, allows the Company to proactively prepare for any emerging vehicle needs based on how new projects and employees are planned or deployed. In this manner, the Crewing Model complements the other fleet tools the Company is developing by ensuring that units are allocated as effectively as possible before and after any new units are purchased. The customer benefits from this because the Company is constantly working to keep its fleet right sized, with as few redundancies as possible.

D. Fleet Utilization Tool

Q. Please explain how the Company captures utilization data for its fleet.

A. All vehicles use a Telematics device that is directly wired to that asset's onboard computer or switching. Each installed Telematic device communicates, via cellular signal in real time, information about the asset status including the unit's exact Global Positioning System ("GPS") location, date, time, mileage driven, and hours in operation. A vehicle is considered in use for any given day when it has traveled five or more (5+) miles at any time or equipment that is in operation for thirty or more (30+) minutes per day. This captured data is then uploaded and compiled on a nightly basis into one tool that can then be used to run reports as needed to manage the operation. This data is compiled into a fleet utilization tool that can provide fleet use by zone, by vehicle type, or department and is used as part of the second phase in the Fleet Replacement Planning Process.

Q. How was this data process developed?

A. The electronic information captured by the Telematics system documents industry standard data points that are used to log key vehicle information. Since 1996, every vehicle

manufactured in the United States has an On-Board Diagnostic ("OBD") port/interface that can easily be made accessible to Telematics systems and their associated electronic data gathering capabilities. The OBD system provides access to a vehicle's Electronic Control Unit, the main computer that controls vehicle engine, transmission, and other key vehicle functions. By connecting directly to the OBD of each vehicle, the Telematics system is able to collect the real-time information required to inform the Company to log the key data points required to document utilization.

Q. How is the Company's utilization data tied to the crewing model?

A. As explained in the crewing model section, vehicles are assigned in response to the requirements of the daily work plan and the employees needed to complete the work. Some types of vehicles, like bucket trucks, are used frequently for common field operations, whereas there are other types of vehicles that are highly specialized and designed for specific tasks that are not always required on a given day/night to serve customers but are no less crucial to properly service customers throughout the state. The Company's utilization data also accounts for the downtime that equipment must undergo when receiving inspections, maintenance and repair, or other ancillary equipment upgrades, and for the fact that some equipment must be available for on-call assignments and off-hour assignments.

Q. Why is this approach to utilization data appropriate for the Company to use?

A. By capturing real-time telematic data from each asset and compiling it in one dataset, the Company obtains the required raw data to detail the exact frequency, duration, and overall use of each asset, and this data is then searchable for reporting utilization rate purposes. Utilization data can illustrate where units may be underutilized. The customer benefits

from this approach because the Company ensures that all vehicles and assets are tracked, monitored for maintenance and safety, and allows for the optimal cost-benefit relationship and return on investment for its fleet. This approach supports the analysis of what assets the Company needs to purchase to be sure that it is replacing vehicles at the end of their lifecycles, and to be sure that the Company is serving customers with safe, capable, and effective equipment.

Q. What conclusions do you draw from the Company's fleet utilization data?

A. The Company's utilization rate data informs us that a continual review of fleet equipment for under-utilized vehicles, what areas of the business they serve, and how that may impact the Company's ability to serve its customers, will be on an ongoing analysis. It is a key tool in determining why and where vehicles may be down (or showing lower utilization rates). For example, vehicles that are down for repair or waiting for parts are different from vehicles that are available but are not being used to serve customers when evaluating utilization rates. The Company analyzes its fleet utilization to determine if there are any redundancies that can be dispositioned in the future, such as through attrition and reallocating to raise utilization to more optimal levels.

E. Benefits

Q. Please summarize the Company's Fleet Replacement Planning Process.

A. The Company's fleet consists of 7,207 units of varying specs utilized for specific tasks to serve customers, divided between the electric and gas sides of the business. Assets referred to as "common units" are utilized by various other departments within the Company to support business operations. The Company employs a Fleet Replacement Planning Process (Replacement Filter, Blended Factor, Cost Data, Utilization Data and Crewing Models) to

determine, in the most cost-effective and efficient manner, which units to replace. The Blended Factor identifies a pool of assets to consider replacing based on the mileage and age of each asset. Fleet cost data helps refine the initial group of eligible vehicles by helping to identify units that have become more costly than their value, or inefficient to maintain in the fleet. By applying crew modeling and utilization analysis, the Company checks to ensure that crew sizes support the potential number of vehicles replaced or added and confirms that replacement assets are appropriate based on usage rates. The customers benefit from this overall process because the systematic efforts noted above attempt to replace and/or add fleet assets at the most beneficial time possible. Each step in the process is designed to specifically identify which assets to add or replace, and the rationale and timing.

Q. What are the benefits of the Fleet Cost Tool for customers?

A. The tool helps the Company make decisions about which units should be replaced or kept by illustrating when the cost of maintaining the units outweighs the cost of a new unit, or investments made in units to keep them in service, which ultimately supports decisions made in the Company's Fleet Vehicle Capital Replacement Plan. The tool allows for visibility of significant investments such as a new engine or transmission in a vehicle that could extend its service life. The customer benefits from this analysis because the Company is using fleet dollars in the most economical way possible.

Q. What are the benefits of the Crewing Model for customers?

A. Having the ability to tie the workforce to the right vehicle by location enables the Company to have visibility to align assets with the workplan by department and location. As the Company strives to be a good steward of the fleet, the model helps validate if additional

units are needed to meet the Company's workplan or, alternatively, if the Company has any surplus units that can be redeployed or retired. Absent this, the Company may end up lacking the appropriate vehicles to complete work for the customers' benefit.

Q. What benefits does fleet utilization data provide for customers?

A. Peak utilization of all vehicles is a balance between fully utilizing purchased assets and having the right asset in place and ready when needed at a moment's notice when responding to outages, new business, or construction situations. Fleet assets other than specialized equipment that are underutilized are not providing the maximum benefit to the customer. As good stewards of its fleet, the Company must provide the most cost-effective methods to ensure that the fleet is a safe and effective part of the service it provides.

The Company's ability to serve its customers reliably, efficiently, and to a high standard requires an equally capable fleet. By methodically incorporating utilization processes that monitor fleet assets, the Company can maintain the fleet to manufacturers' specifications, as well as addressing the periodic wear and tear that comes with operating vehicles in often extreme conditions. Utilization data that monitors each type of vehicle can also assure that the Company is earning the best return on investment for the expected environment in which said vehicle is designed to operate. For example, the Company expects that investing in a sedan should provide a life expectancy of seven years and approximately 150,000 miles under normal service. Utilization for a vehicle of this type may differ as compared to a utility truck sent as needed to address concerns in the field or support customers as the need arises. However, for both types of vehicles, regular monitoring of utilization reports will help the Company plan for the replacement of each vehicle with regular use over time. Additionally, analysis of any under-utilized vehicles

will inform decisions on how many future investments in that type of vehicle are made going forward. Customers benefit when the Company is making best use of its fleet to deliver service. Utilization data helps the Company right-size its fleet by identifying where additional units are needed to accommodate the Company's workforce, if there are any surplus units, and if existing units can be more effectively used by the Company, such as by moving units to a new location or new department.

Q. Have there been right sizing efforts that benefit the customer?

A. Yes. Since mid-2022, the Company has reduced its total number of units by approximately 450 units utilizing the tools described above. These right sizing efforts benefit the customer by reducing overall cost through reductions and/or allowing a particular unit to be effectively utilized in support of serving customers.

Q. How does the Company's overall Fleet Vehicle Capital Replacement Plan benefit customers?

A. Overall, the Fleet Vehicle Capital Replacement Plan allows the Company to retire and replace vehicles in a cost-effective way by using qualitative and quantitative inputs to identify units for replacement, particularly by identifying those units with high maintenance costs and exhausted expected useful lifespans. Retiring and replacing those units in a systematic way is designed to keep maintenance costs down while ensuring that vehicles are available when needed to serve customers. The replacement planning process is a constantly self-evaluating cycle that relies on the data the fleet itself generates over time (mileage, age, and life cycle expectancy), inspections, maintenance and repair costs, and the local expertise to assist in prioritizing how the Company replaces units in the fleet. The customer benefits from this replacement planning process because the fleet is a crucial

part of the overall service the Company provides. A replacement plan allows the Company to provide a safe, reliable, and cost-effective fleet to respond timely to utility outages, damaged utility service, utility service renewals, and new construction requests.

Q. Are there further benefits related to safety, quality, and the planet when determining the Fleet Vehicle Capital Replacement Plan?

A. Yes. By replacing vehicles in the fleet, newly introduced features from vehicle manufacturers are regularly incorporated into the Company's fleet, such as the following:

Safety-

- Backup sensors and rear-view cameras. This feature allows for safer backing, resulting in fewer rearward collisions, reducing vehicle and property damage, and increasing safety for the Company's customers and employees as well as collision avoidance and auto emergency braking, reducing collisions by advanced driver warning and applying brakes in advance of collision.

- Reduced stopping distance requirement from the Federal Motor Carrier vehicle safety standard for class 6-8 trucks. The standard distance required to stop a commercial vehicle was reduced, (National Highway Traffic Safety Administration 49 CFR Part 571, requiring a 30% reduction in stopping distance compared to currently required levels), which led to equipping trucks with larger braking systems to avoid collisions on buses and trucks manufactured on or after July 1, 2005.

- Light Emitting Diode ("LED") headlight technology. This allows a driver to see further down the road giving the driver more time to react to a situation. LED headlights also save money due to less frequent bulb changes, thereby reducing time under repair.

Quality-

- Materials to manufacture vehicles are continuously advancing. For example, the Ford F-150 body is now stamped out of military grade aluminum, making the truck lighter, which increases fuel economy. Another added benefit of aluminum bodies is corrosion resistance, meaning less time and money spent repairing corrosion problems.

- Over the last 10 years, diesel engine exhaust gas recirculation coolers have improved, eliminating the need to replace them as frequently. This saves approximately $4,000 per replacement, where such replacements occurred about every two years.

Planet–

- To align with National Highway Traffic Safety Administration's corporate average fuel economy standards, new vehicles are becoming more fuel efficient to align with their regulations. When replacing units within an appropriate lifecycle, the Company has an opportunity to purchase more fuel-efficient vehicles, including fully electric and plug-in hybrid vehicles where appropriate, ultimately reducing the Company's carbon footprint.

- Fossil fuel powered vehicles may be replaced with an EV if data supports electrification in that instance and could be a more fuel-efficient mode of transportation.

FLEET ELECTRIFICATION STRATEGY

Q. Does the Company plan to increase the number of EVs in its internal fleet?

A. Yes, the Company is planning to increase the number of EVs in its fleet to reduce fleet fuel, maintenance, and operating costs, as well as lowering carbon dioxide tailpipe emissions to reduce greenhouse gases. For purposes of this testimony, the Edison Electric Institute's definition of an EV includes all vehicles with a plug, including Battery EV, Plug-in Hybrids, and anti-idle job site work systems such as electric Power Take Off systems ("ePTO") units.

Q. How many EVs does the Company have in its internal fleet currently?

A. The Company's fleet currently operates 302 EVs, representing approximately 5% of powered units in the overall fleet.

Q. Does the Company have a target goal for electrification of its internal fleet?

A. Yes, as noted by the Michigan Council for Future Mobility and Electrification in its 2021 report, the decade ending in 2030 will be notable in that the growth of EVs in the state will present new opportunities for the Company and its customers.[2] This is consistent with the

[2] cfme_report_2021_02.pdf (michigan.gov): https://www.michigan.gov/leo/-/media/Project/Websites/leo/Folder28/cfme_report_2021_02.pdf

testimony of Company witness Jeffrey A. Myrom in the Company's most recent electric rate case, Case No. U-21585. Leading by example, the Company has, therefore, set a goal of electrifying 30% of its internal fleet by the year 2030, including light, medium, and heavy-duty vehicles (class 1 through class 6 and higher), equipment and powered trailers, as well as electrifying all class 1 and 2 (light duty) vehicles after 2030.

Q. How many vehicles does the Company plan to convert to electricity as a source of fuel by 2030?

A. The internal fleet currently consists of approximately 5,700 powered vehicles eligible for replacement by potential EVs. This includes sedans, pickup trucks, bucket trucks, forklifts, and others. Electrifying 30% of these units would result in the replacement of approximately 1,700 internal combustion engine ("ICE") units with fully or partially EV powered units by 2030.

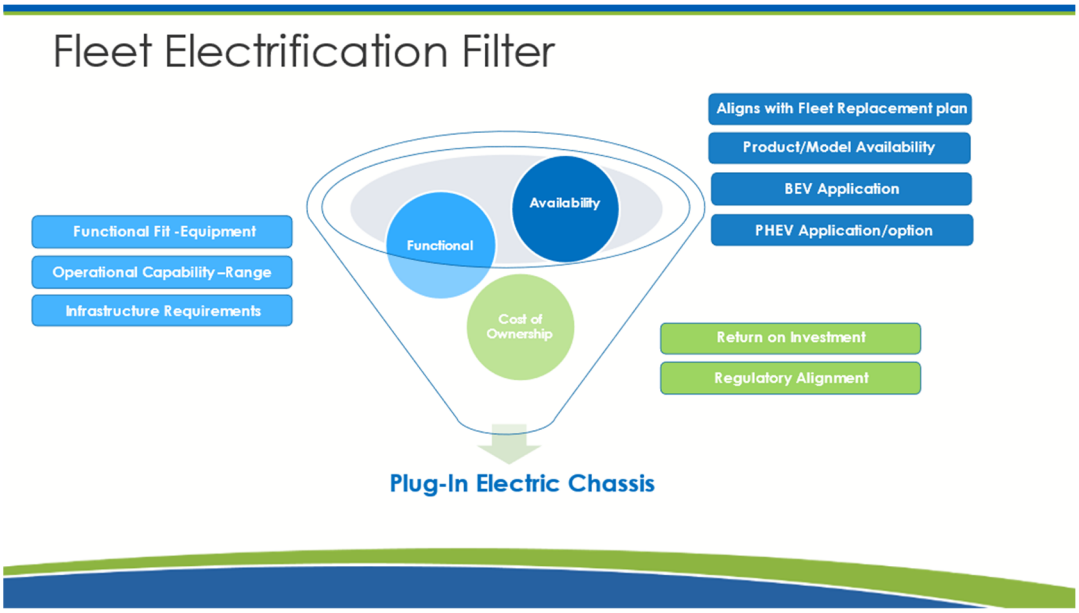
Q. What types of vehicles does the Company expect to replace with EVs?

A. The Company expects that most of the initial ICE vehicles it will replace will be sedans and pickup trucks; however, as battery technology develops, there will be increasing availability for medium and heavy-duty vehicles to enter the market. For example, the Company has purchased one of the first available all electric bucket trucks in the world, which was delivered in the third quarter of 2024, as well as 20 all-electric pickup trucks. The Company will deploy the electric bucket truck in its Grand Rapids location and has installed a DC Fast Charger there to support it.

Q. How will the Company determine opportunities to replace ICE vehicles with EVs?

A. The same replacement process, as discussed earlier in my testimony, will be used to determine opportunities to replace ICE vehicles with EVs, including the use of the Blended

Factor, unit age, and overall condition analysis for each unit that has reached its end of life. Under this process, as a unit is targeted for replacement and reviewed according to the Replacement Plan, the unit is also considered for replacement with an EV. As the Electrification Filter shown below shows, consideration for electrification includes assessing a suitable replacement that is available in market, would have a functional role within the fleet, and lower cost of ownership. If the ICE under consideration for replacement meets the criteria required to pass through the filter, the unit is considered as an opportunity for replacement with an EV.



Q. Why is the Company concerned by functional fit and equipment considerations?

A. The Company partners with operational departments to understand how the potential replacement of an ICE vehicle with an EV will impact how teams complete their work. It is important to understand vehicle travel patterns, including mileage and driving duration, to assure that EVs are capable of supporting the work and have the travel range the Company needs to serve customers without compromise.

Q. Why is the Company considering range concerns with EVs?

A. As noted above, mileage range is a top consideration in determining how the Company integrates EVs into the fleet. It is critical to understand how current vehicles operate to determine potential EV replacement options, as well as infrastructure preparedness. The Company is utilizing its trip data, including mileage and location, to understand the best fit for each EV it is considering.

Q. Why is functional fit a critical part of the EV decision making process?

A. As with all other vehicles, the Company strives to ensure its Fleet aligns with industry best practices to serve the customer safely and efficiently. It will be important to consider, in addition to range, how an EV will support each department's ability to use it to its fullest capabilities, such as carrying tools and employees as required by the work.

Q. How will the Company determine if EVs are performing as expected?

A. The Company will be expanding its internal focus groups to provide real world feedback on barriers and opportunities to continuously improve how the Company adapts EVs in various operational environments. The Company will also study how EVs perform from a cost perspective, with lower maintenance and fuel costs expected.

Q. In what ways are EVs more beneficial than ICE vehicles?

A. Most of the benefits gained from utilizing EVs or battery-assisted systems arises from the changeover to electricity as the main source of energy, instead of gasoline or diesel fuels and petroleum-based maintenance materials. Electric motors require much less powertrain maintenance and repair, resulting in reduced maintenance costs, which is one of the key benefits of electrifying fleet units. A fully EV (battery) powered vehicle can also have up to 80% fewer parts than its ICE counterpart. With fewer internal parts, electric motors

operate with less friction and more efficient use of energy. Many ICE vehicle parts require frequent and costly maintenance routines. Further, up to 65% of the heat energy produced by an ICE is wasted, requiring cooling systems which are prone to wear and eventual failure.

Q. Can you please give examples of reductions in maintenance that will arise out of a transition from ICE vehicles to EVs?

A. ICE vehicles contain hundreds of oil-lubricated parts that are required to convert the combustion of fossil fuels into mechanical energy. Fluid changes extend to other components needed at various intervals in addition to engines and transmissions, including transfer cases and differentials throughout the life of all ICE vehicles. All these systems require regular maintenance and the associated costs in labor, parts, and materials to keep them at optimum performance and longevity. Over time, however, these components continue to wear even with diligent maintenance. This wear often leads to overheating issues, damaged or broken hoses, worn coolant pumps, or engine failure with the associated down time while undergoing repairs. EVs, on the other hand, do not require oil changes, spark plugs, fan belts, or tune ups. EVs also do not have transmission fluids that require periodic fluid changes, which makes them less prone to failure. Further, since an EV drive train requires less attention from a maintenance perspective, there is a reduced need for labor and/or material costs associated with this aspect of maintaining an EV. Plug-in EV hybrids often work with an ICE in conjunction with electric motors, reducing the fuel requirements for units equipped this way. Depending on the vehicle's configuration, a hybrid that features an ICE may need a maintenance schedule like a regular ICE vehicle;

however, in most cases, plug-in hybrids help reduce overall fuel consumption with extended periodic maintenance requirements.

Q. Are there other tools available to reduce fossil fuel consumption in ICE vehicles?

A. Yes, there are idle-mitigation technologies, using plug-in battery systems, designed to reduce fuel consumption by reducing idle hours required to operate ancillary equipment such as a boom on a bucket truck. By employing a plug-in battery and electric motor, for example, ePTO units can power hydraulic systems for short periods, reducing fuel consumption and engine wear. When engaged at a jobsite, an ePTO system can shut an idling engine off, and a battery-powered motor then powers the hydraulics needed to position the boom and bucket, as well as powering the climate control system in the cab. As a result, the bucket truck will operate quietly while the operator performs work near a customer's home because the sound of an idling diesel will not be present while the ePTO system is engaged. The Company already employs this technology to help reduce idling hours on several specs that operate booms on bucket trucks and cabin climate control. Additionally, ePTO systems can reduce fleet's overall carbon dioxide tailpipe emissions, as well as diesel particulates.

Q. Has the Company undergone a concierge cost benefit analysis to help plan for internal EVs?

A. Per Case No. U-20963, the Company has partnered with CALSTART, a national non-profit with over 30 years' experience in the private and public sectors with a proven track record working with over 280 member companies and agencies to build business cases for clean transportation technology adoption. CALSTART is a nationally respected team of fleet electrification experts who were selected by the Company via a competitive Request For

Proposal. CALSTART has completed numerous fleet electrification assessments for external customers, in addition to the Company's assessment. The Company's fleet assessments were conducted between August 2022 and October 2023 and analyzed the Company's light, medium, and heavy-duty fleet vehicles, by location, and daily miles driven to provide approximate load demand by location. EV location determination helps in understanding potential carbon emission avoidance and cost benefit analysis.

Q. Does the Company solely rely on the CALSTART assessments for determining what EV to purchase?

A. The Company does not rely solely on the CALSTART assessment in its planning for EVs. CALSTART used the Company's own fleet-generated data to compile a list of recommendations for vehicle locations that are potentially suitable for electrification, the estimated load demand for those locations, and the associated charging information to support them. This information assists the Company during the decision-making process when considering EVs.

Q. What quantifiable benefits of electrifying vehicles did CALSTART's assessment determine?

A. CALSTART's assessment, noted above, concluded that the Company has the potential to lower fleet's overall fuel and maintenance costs by approximately 70%, excluding vehicle purchase price, combined over the lifetime of the vehicles that are electrified. The assessment also concluded that the Company could potentially reduce tailpipe emissions by approximately 90,000 metric tons.

Q. Did the assessments provide suggestions for EV infrastructure support?

A. The assessments provide specific location-based electric load demand estimates for the light duty EVs planned for replacement, as well as electricity as fuel cost estimates based on current mileage driven by ICE vehicles. For each service center/office location, the Company's ICE light-duty fleet data was analyzed for average daily miles driven and applied this information to determine the appropriate level of charger (Level 1 or Level 2) and the estimated corresponding energy demand for each vehicle. With this information, the Company can plan for the specific infrastructure electrical upgrades needed to support the installation of Electric Vehicle Supply Equipment ("EVSE") at respective service centers with a measure of predictability based on the information the Company's ICE fleet has generated.

Q Is there a cost difference between EVs and conventional fossil fuel vehicles?

A. Depending on make, model, and mileage range ratings, the purchase cost for an EV can vary as compared to an ICE vehicle. Currently, there are usually higher purchase costs associated with EVs that are comparable to ICE vehicles used by the Company to service its customers, such as all electric pick-up trucks.

Q. Can you provide an example of a suitable EV for the Company?

A. When considering an EV replacement, the Company seeks the closest EV equivalent to the out of lifecycle ICE under consideration for replacement. Currently, vehicles are more closely aligning with pickup trucks and economical sedans as most suitable for transportation and operational support. The Company is also interested in the business and operational stability of the manufacturer to assure continued support over of the lifetime of the vehicle.

Q. Are there other associated projects being planned to support vehicle electrification efforts?

A. Yes. To support the growth of EVs, the Company must plan for the increased electric load demands at most of its service centers to charge the EV units at those service centers. Since each center location will have a varying number of EVs and load demands, each location will require a specific power demand-based upgrade of its electric infrastructure for the installation of EVSE, also commonly known as "chargers." As noted earlier in my testimony, fleet has undergone a detailed data-based assessment by CALSTART to forecast the load demands each facility may need to charge EVs daily.

Q. How many potential EV opportunities are identified in the Five-Year Purchase Plan?

A. Based on the currently available EV vehicles offered by manufacturers, the Five-Year Purchase Plan currently identifies approximately 120 to 130 potential opportunities for a suitable 1:1 replacement of an ICE with an EV based on replacing units that have reached their end of life. Most of these vehicles are light duty pick-up trucks, and plug-in battery idle mitigation units on bucket trucks. There are about 22 light duty vehicles that could be replaced with an EV in 2026, and 20 opportunities in 2027, 23 in 2028, 22 in 2029, and approximately 25 to 30 units in 2030. With limited opportunities to make ICE to EV replacements through 2027, the Company would need to invest additional funding above the currently approved capital replacement funding for the purchase of approximately 450 EVs over and above what the Purchase Plan identifies as a replaceable unit each year in 2028, 2029, and 2030 to reach the Company's goal of approximately 1,700 EVs.

Q. Is the market for vehicle electrification currently able to supply the vehicles needed to support the Company's goal?

A. Lead times for some EVs and vehicles equipped with idle mitigation systems are often two or more years out. The resources required by manufacturers to build enough units to meet high demand are not aligned, which has often led to short supplies for both commercial and private customers; however, the market's availability of EVs suitable as fleet vehicles is still a relatively small part of the EV market. Currently, a substantial portion of the EV market consists of vehicles that do not meet the criteria for cost and features best suited for use by the Company. For example, the Company prefers Original Equipment Manufacturer ("OEM") vehicles from Michigan-based companies, such as General Motors and Ford, as well as meeting all the requirements noted as part of the Fleet Electrification Filter. The recent fall in EV demand for EV pick-up trucks has shifted manufacturer focus to other models or delayed the development of new EVs. There are many startup companies with potentially viable EV units; however, the Company prefers to limit the potential exposure to the risks associated with startup company products.

Q. How does limited availability of EVs affect the Company's goal?

A. The Company's ability to increase the number of EV units in the fleet remains flat through 2027. At this time, limited market EV availability may prevent the Company from ordering a suitable number of EV units needed to affect a more linear glidepath toward the 2030 goal. Also, the EV opportunities identified in the Purchase Plan averages about 20 to 25 units per year. If the Company continues to purchase EV units at this pace per year, the goal to electrify 30% of the fleet will not be met by 2030.

Q. What EV units does the Company plan to purchase for the Test Year?

A. The Company is planning to replace 10 ICE pick-up trucks with 10 plug-in electric EV pick-up trucks.

Q. How will the Company determine the locations to assign EV vehicles?

A. All EVs will be assigned to departments and teams that are best able to utilize the benefits of an EV during their daily job functions. As discussed earlier in my testimony, the assessment from CALSTART provides a summary of miles driven by location, allowing the Company to understand where an EV can be best utilized. For example, where the data shows an ICE pickup truck is typically driven 75 to 150 miles per day and returns to its respective service center, that vehicle could be eligible to be replaced with an EV of similar capability and range because the data suggests a good fit for an EV. The Company can reference the assessment data to help make the most informed decisions on their deployment. The Company also partners with operations to determine if an EV will meet the requirements of their work processes at a particular location.

Q. What associated infrastructure support will the EVs planned for the Test Year require?

A. The EV units will require chargers installed at their planned respective headquarters to support their charging requirements. The planned headquarter locations that will need EV chargers installed are as follows: Jackson, Royal Oak, Lansing, Bay City, Battle Creek, and Adrian.

Q. How does electrification of 30% of the Company's fleet by 2030 benefit the customer?

A. The Company's efforts to electrify a portion of the internal fleet could benefit the customer in several ways. The Company seeks to lower Fleet's overall operating costs by reducing

its reliance on fossil fuels, which will bring lowered maintenance costs for reasons mentioned earlier in this testimony. By shifting the cost of refueling an ICE unit from gasoline or diesel to overnight charging, the Company can save money on fuel wherever mileage powered by fossil fuels can be shifted to lower cost charging overnight rates. Over the lifetime of these vehicles, by utilizing electricity to power 30% of the fleet, the Company seeks to leverage the relative stability and lower cost electricity offers over the more volatile cost of petroleum-based fuels and lubricants. Reducing the Company's reliance on ICE vehicles brings significant reductions in the maintenance costs associated with the upkeep of fossil fuel-based drivetrains. With fewer mechanical parts to maintain, EVs require lower maintenance budgets and fewer parts that can potentially fail over the lifetime of the vehicle.

Lastly, by lowering its reliance on fossil fuels, the Company seeks to lower its overall carbon dioxide emissions from Fleet's operations. Fully electrified vehicles have zero tailpipe emissions and, where applicable, hybrid vehicles and other technologies (like idle mitigating ePTO systems) also offer carbon reductions as well. Where idle mitigation systems are employed with diesel engines, reduced idling lowers particulates, or soot, generated with the combustion of diesel fuel. The Company's customers will benefit from the efforts to mitigate pollution, reduce greenhouse gas emissions, and lower its overall operating costs related to operating its internal fleet.

FLEET SERVICES CAPITAL SPENDING PROJECTIONS

Q. Please describe the capital expenditures related to Fleet Services as shown on Exhibit A-12 (QAG-1), Schedule B-5.6.

A. Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, provides electric Fleet Services capital spending, broken down into five capital spending categories: (i) Fleet Vehicle Capital Replacement, (ii) Fleet Vehicle Electrification, (iii) Fleet Expansion, (iv) Fleet Business Partner Funded, and (v) Fleet Tools - Garage. Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, provides these capital expenditures with actuals for the 12 months ended December 31, 2024; projections for the 12 months ending December 31, 2025; 4 months ending April 30, 2026; 16 months ending April 30, 2026; and projections for the 12 months ending April 30, 2027, which is the test year in this case. For the historical year, 12 months ended December 31, 2024, the Company incurred Fleet Services capital expenditures in the amount of $16.628 million. The Company is projecting electric Fleet Services capital expenditures to be $21.581 million for the 12 months ending December 31, 2025; $4.368 million for the 4 months ending April 30, 2026; $25.948 million for the 16 months ending April 30, 2026; and $67.947 million in the projected test year ending April 30, 2027, as set forth in Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, line 6, columns (b) through (f), respectively.

Q. Are there any contingency costs included in the Company's projected Electric Fleet Services capital expenditures?

A. No.

Q. What types of expenditures are included in Fleet Vehicle Capital Replacement Plan and Expansion high voltage distribution ("HVD") capital spending?

A. Details of the Fleet Vehicle Capital Replacement Plan are included at Exhibit A-104 (QAG-5).

Q. What types of expenditures are included in Fleet Vehicle Capital Replacement Plan and Fleet Vehicle Electrification capital spending?

A. Fleet vehicle electrification expenditures include the offset cost of 10 EV pickup trucks, two units for electric and eight units for common use, as well as 12 Altec JEMS ePTO systems in spec 64 bucket trucks.

Q. What types of expenditures are included in Fleet Business Partner Funded?

A. Fleet Business Partner Funded expenditures include one pick-up truck supporting the Company's solar renewable generation sites.

Q. What types of expenditures are included in Fleet Tools?

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment to properly and safely service and repair fleet vehicles, equipment, and trailers. This is described in detail later in my direct testimony.

Q. How did you determine the appropriate distribution of capital costs among the cost categories shown on Exhibit A-12 (QAG-1), Schedule B-5.6?

A. As required by the Commission's filing requirements, the Company itemized the capital investments for Transportation Equipment by using the following cost categories: contractor, labor, materials, business expenses, and other. The Company breaks out these cost categories by calculating a five-year historical average of each of the Commission's prescribed cost categories from years 2020 thru 2024 as a percentage of total

Transportation Equipment investment over that same period. The five-year historical average for each cost category was then applied to the Transportation Equipment Program's projected capital spending for the bridge year and the test year to arrive at estimates for each cost category (i.e. contractor, labor, materials, business expenses, and other). This method is consistent for the projected test year presented in Exhibit A-12 (QAG-1), Schedule B-5.6, pages 5 and 6.

A. Fleet Vehicle Capital Replacement Plan

Q. What level of Fleet Vehicle Capital Replacement Plan spending is proposed in this case?

A. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, the Company is proposing to spend $19.882 million in the 2025 bridge year; $4.282 million for the 4 months ending April 30, 2026; $24.164 million for the 16 months ending April 30, 2026; and $20.778 million in the 12 months ending April 30, 2027 test year on Fleet Vehicle Capital Replacement Plan spending.

Q. How did the Company determine its 2024 through 2027 Fleet Vehicle Capital Replacement Plan for the instant case, including the appropriate level of investment?

A. The Company is keeping Fleet Vehicle Capital Replacement Plan spending in 2024 through 2027 at historical spending levels, adjusted for inflation, based on what the Commission has previously approved for "lifecycle replacement spending." By remaining at this level for 2024 through 2027, the Company is demonstrating its commitment to keeping costs affordable for customers.

Q. How did the Company develop the list of vehicles that is projected to be purchased in years 2024 through 2027 of this case?

A. The specific units that the Company plans to purchase 2024 through 2027 are also shown in Exhibit A-104 (QAG-5). The Company produced an initial list of vehicles for replacement using the Blended Factor algorithm described earlier in my testimony, with a spreadsheet showing a Blended Factor percentage for each vehicle in the Company's fleet. This list was prioritized by the Blended Factor percentage to highlight vehicles that generate a positive (above 0.0%) percentage (the mathematical result of the Blended Factor calculation), which indicates that a vehicle has reached its expected life. Following the Blended Factor Analysis, as described previously in this testimony, the Replacement Plan filter included a review of market availability. By reviewing market availability, the Company can determine which replacement specifications can be expected for delivery through 2027. Vehicles that are likely not available for delivery in 2025 were not considered for replacement. To further refine the list of vehicles, standard crewing models were assessed. Though the Company will be continuing an analysis on right sizing, standard modeling helped guide the decision-making process.

Q. Was there additional analysis in determining the Fleet Vehicle Capital Replacement Plan for 2025 and 2026?

A. Yes. The list was further reviewed from a cost and utilization perspective. By assessing how often vehicles are used, the Company selected vehicles with a higher utilization rate when compared to similar specifications. The Company further narrowed the initial Blended Factor-based list based on fleet stakeholders' input on condition. In this step, vehicles were assessed by age, mileage, and overall condition, and associated operating

costs and mechanical improvements, such as a newly installed engine. Vehicles that received recent substantial investments (new engines, for example) are removed from the potential replacement list because their expected life is generally extended following such investments.

Q. Does the Company anticipate variances in future fleet spending?

A. While the Company attempts to be as precise as possible in the Fleet Replacement Plan, there is the potential for variances slightly above or below projected budget due to the nature of the fleet business that includes supply chain challenges. However, the Company continues to be good stewards of the fleet by working to meet all projected expenditures as close to targeted goals as possible.

B. Fleet Vehicle Electrification

Q. In the projected test year, 12 months ending April 30, 2027, the Company is projecting an investment of $840,000 for EVs. What is included in this amount?

A. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, the Company is proposing to spend $840,000 in the 12 months ending April 30, 2027 test year on Fleet Vehicle Electrification. This sum includes ICE to EV replacements and $600,000 to install JEMS idle mitigation units on each of 12 bucket trucks (vehicle spec 64) as shown in Exhibit A-104 (QAG-5).

Q. Why are the expenditures presented for Fleet electrification appropriate?

A. Fleet expenditures requested will be used to bridge the price gap difference between a standard ICE pickup truck and a plug-in EV pickup truck of similar function. The proposed spending would fund the purchase price difference between a standard ICE pickup truck and its EV equivalent. The purchase price difference between an ICE pickup truck chassis

and an EV pickup truck chassis is approximately $40,000, totaling approximately $240,000 for 10 EV pick-up trucks. The ePTO idle reduction units are effective tools in lowering idle hours, fuel costs, and tailpipe emissions on bucket trucks. The addition of these EVs will further the Company's efforts to reduce fuel and maintenance costs, as well as its overall carbon footprint.

Q. Why is the Company requesting only the purchase price difference between an ICE vehicle and an EV in this case?

A. Due to these vehicles being part of the replacement plan process, the funding to replace an ICE chassis is already being requested as part of the capital replacement plan. Therefore, the Company is only requesting to add the purchase price difference between a standard ICE chassis and the electrification cost of its replacement unit.

Q. How do these capital expenditures benefit the customers?

A. The vehicle electrification expenditures will benefit the customer in several ways. EVs and plug-in hybrids are expected to lower the Company's overall fuel and maintenance costs as compared to ICE powered vehicles. The EVs proposed also could offer significant potential reductions in greenhouse gas emissions, increasing the Company's carbon avoidance efforts, while providing service to customers with less pollution at lower cost. Lastly, the units proposed for the Test Year will further the Company's learnings on EV best practices, planning, and deployment as it increases fleet electrification.

C. Fleet Expansion Spending

Q. Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, contains a line item related to Fleet Expansion expenditures for HVD. Please explain what this is.

A. The Company intends to make investments of $648,000 in the 12 months ending December 31, 2025, $15,170,000 in the 12 months ending December 31, 2026, and $46,070,000 in the test year to support workforce expansion efforts in Electric Operations. The purchases include pickup trucks with specific upfits that will be used by the Electric Operations substations to perform work related to HVD operations. See Exhibit A-104 (QAG-5). The purpose of this workforce expansion is to continue facilitating the Company's increasing investment in electric distribution infrastructure as outlined in the testimony of Company witness Michael P. Kelly.

Q. What concerns does Fleet Services have if the proposed capital expenditure amounts for expansion are not approved?

A. If the proposed capital expenditure amounts for expansion are not approved, the Company risks stranding labor as some members of the Company workforce that construct and maintain electric distribution infrastructure will be without equipment and vehicles necessary to perform the work.

D. Fleet Business Partner Funded

Q. In the 12 months ending December 31, 2024, the Company funded a business partner funded investment of $55,000. What is included in this amount?

A. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, line 4, column (b), the Company invested approximately $55,000 to acquire a pickup truck. This unit is used by

Company personnel responsible for maintaining batteries at the Company's solar renewable generation sites.

Q. How did you determine the needed level of spending for the partner funded equipment?

A. The level of spending represents vehicle costs including tax, title, license and delivery.

Q. How do these capital expenditures benefit the customers?

A. See the direct testimony of Company witness Thomas P. Clark for a summary of the benefits of the Company's solar generation investments.

E. Fleet Tools

Q. What kind of purchases are included in Fleet Tools?

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment required to properly service and repair fleet vehicles, equipment, and trailers.

Q. What level of expenditures is included in this rate case for Fleet Tools?

A As shown on Exhibit A-12 (QAG-1), Schedule B-5.6, page 4 the Company spent $280,000 in the 2024 historical year; $251,000 for the 12 months ending December 31, 2025; $336,000 for the 16 months ending April 30, 2026; and $259,000 in the 12 months ending April 30th, 2027, test year on Fleet Garage Tools. A further breakdown of this tooling type per year can be found on Exhibit A-104 (QAG-5).

Q. Why are the expenditures presented for Fleet Tools appropriate?

A. To properly repair vehicles in a compliant, safe, and efficient manner, it is necessary to have the right tool for the task at hand. The tooling can be anything from diagnostic tooling, electronic service information, tool sets, or a new air conditioning

recovery/recycle/recharge machine required to properly service R1234yf refrigerant. Diagnostic tooling is necessary for the repair of most vehicle systems such as the engine, transmission, air bag, lighting, and anti-lock brakes. This tooling requires updates to maintain access to new vehicle models. Electronic service information is required to diagnose vehicle concerns and to follow the manufacturer's recommended repair procedures. Additional tooling such as hydraulic torque wrenches are critical in ensuring that high torque fasteners requiring very high torque applications are properly set and adjusted to manufacturer torque specifications to ensure safe repairs and inspections. Maintenance equipment, such as an R1234yf air conditioning machine, are required to meet Environmental Protection Agency standards for safely recovering and recharging air conditioning systems on newer model year vehicles.

Q. What benefits does this level of Fleet Tools spending provide to customers?

A. Across the state, the Company has 36 locations where Fleet mechanics are permanently stationed to perform their daily work. The Company also has remote sites, training facilities, and jobsite reporting locations where repairs to vehicles and equipment are also performed. The projected Fleet Tools for 2025 spending is approximately $494,000 for the entire Company, or approximately $13,700 for each of the 36 locations where mechanics are stationed. The electric allocation of this total is approximately $251,000. Each year, the Company replaces and updates outdated or unrepairable shop equipment such as floor jacks, diagnostic equipment, tire machines, and welders. The benefit to customers of having tools in good order is less downtime for vehicles and reduced maintenance expenses because the Company is not solely reliant on outside repair shops to complete the work needed to keep vehicles active. Most repair and maintenance items are

performed by the Company's in-house mechanics; therefore, it is imperative that the Company maintain a complete and updated inventory of tools to complete the work required.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Quentin A. Guinn, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Quentin A. Guinn who previously filed direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address Attorney General witness Sebastian Coppola's recommendations that the Michigan Public Service Commission ("MPSC" or the "Commission") (i) remove forecasted capital expenditures in the amount of $4,600,000 and $6,146,000 for the 16 months ending April 30, 2026 related to the Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall, respectively; (ii) remove projected test year capital expenditures in the amount of $3,390,000 and $12,107,000 related to the Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall, respectively; (iii) remove projected test year expenditures in the amount of $2,706,000 for Emergent Repairs; (iv) remove forecasted test year capital expenditures in the amount of $4,371,000 related to the Vehicle Capital Replacement Plan; (v) remove forecasted test year capital expenditures in the amount of $28,771,000 for the Vehicle Expansion Plan; and (vi) direct the Company to present a thorough plan in its next electric rate case addressing the utilization of vehicles and field equipment and the impact of reduced vehicle purchases in future years. Next, I will address MPSC Staff ("Staff") witness Jessica Duell's recommendations that the Commission (i) remove forecasted capital expenditures

in the amount of $1,306,000 and $1,129,500 for the four months ending April 30, 2026 related to the Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall, respectively; and (ii) remove forecasted test year capital expenditures in the amount of $1,695,000 and $6,053,500 related to the Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall, respectively. I will also address Natural Resources Defense Counsel, Sierra Club, and Citizen's Utility Board of Michigan (collectively ("MNSC") witness Douglas B. Jester's recommendation that the Company should revise its fleet electrification target so that all light-duty vehicle replacements are fulfilled by electric vehicles no later than 2030. Finally, I will withdraw from this case test year capital expenditures in the amount of $98,200 for Other Equipment and $948,000 for Emergent Repairs.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. No.

Q. Does the Company agree with Attorney General witness Coppola's assertion on pages 82 through 84 of his direct testimony that the Commission should remove forecasted capital expenditures associated with Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall because the Company has not made a compelling case that having two fully staffed control/dispatch centers is advantageous and in the best interest of customers?

A. No. As outlined in the rebuttal testimony of Company witness Andrew R. Snider, staffing both control/dispatch centers is essential for operational resilience and risk mitigation.

Q. Does the Company agree with Attorney General witness Coppola's assertion on pages 84 and 85 of his direct testimony that the Commission should remove from rate base in this rate case forecasted capital expenditures for Emergent Repairs because they are "placeholder amounts"?

A. No. Emergent Repairs includes unplanned corrective maintenance and break fix repair of assets. Specific projects that constitute these projected expenses are unknowable in advance. For this reason, the Company uses a five-year average to determine Emergent Repair capital expenditures. The Commission has accepted this rationale and granted the Company recovery for Emergent Repairs in multiple prior rate cases including Case Nos. U-21806, U-21585, U-21389, U-21224, and U-20963.

Q. Does the Company agree with Attorney General witness Coppola's assertion on pages 87 and 88 of his direct testimony that the Commission should remove forecasted capital expenditures for the Vehicle Capital Replacement Plan because the inflation adjusted cost of the units requested for the projected test year, using a three-year historical average (2022-2024), is less than the total amount requested for the projected test year?

A. No. The method used by Attorney General witness Coppola to determine the projected test year amount for the Vehicle Capital Replacement Plan is incorrect. The use of a three-year historical average is insufficient to maintain the Company's Vehicle Capital Replacement Plan, which brings with it increased maintenance expense. Beginning with the test year amount of $17,943,000 allowed by the Commission for the Vehicle Capital Replacement Plan in Case No. U-20963, the Company calculates each successive calendar year amount for the Vehicle Capital Replacement Plan by adding an inflation factor to the previous

calendar year's amount. The projected test year amount in each case is then pro-rated accordingly. The Commission has approved the use of this method in every rate case since Case No. U-20963.

Q. On pages 85 and 86 of his direct testimony, Attorney General witness Coppola contends that the Company's capital expenditures for the Vehicle Capital Expansion Plan, shown on Exhibit A-104 (QAG-5), line 3, should be reduced because Mr. Coppola's direct testimony in this case proposed to (i) reject the Company's overhead to undergrounding program and (ii) reduced the Company's low voltage distribution ("LVD") capital programs and projects. Do you agree?

A. No. As outlined in the rebuttal testimony of Company witness Michael P. Kelly, the reliability benefits of the undergrounding program and other LVD capital program and projects far exceed the cost of alternatives to improving reliability. In addition, the Company faces an acute risk of some members of its frontline workforce being without vehicles and equipment necessary to perform reliability work (i.e. stranded labor) should the Vehicle Capital Expansion Plan be disallowed as recommended by Mr. Coppola.

Q. On page 89 of his direct testimony, Attorney General witness Coppola recommends that the Commission direct the Company to present a thorough plan in its next electric rate case that addresses the utilization of vehicles and field equipment and the impact of reduced vehicle purchases in future years. Do you agree?

A. Yes. The Company will present a thorough plan in the next electric rate case that addresses the utilization of vehicles and field equipment and the impact of reduced vehicle purchases in future years.

Q. Does the Company agree with Staff witness Duell's recommendations, on pages 19 through 20 of her direct testimony, that the Commission reduce forecasted capital expenditures associated with the Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall because it underspent what was requested in Case No. U-21585?

A. No. As outlined in the rebuttal testimony of Company witness Snider, the Control Dispatch Center project was fully disallowed in Case No. U-21585. Therefore, the projected spend in Case No. U-21585 is not relevant in this case nor was the Company required to execute the projected spend in Case No. U-21585.

Q. Do you agree with MNSC witness Jester's recommendation, at pages 16 through 18 of his direct testimony, that the Company should revise its fleet electrification target so that all light-duty vehicle replacements are fulfilled by electric vehicles no later than 2030?

A. No. To fulfill all light-duty vehicle replacements with electric vehicles no later than 2030 would require the Company to depart from the Fleet Capital Replacement Plan Filter and Blended Factor methods outlined in my direct testimony and used to prioritize fleet replacement purchases. The Commission has approved the Company's use of these methods to prioritize fleet replacement purchases. In addition, the Company would be required to determine what amount of Vehicle Capital Replacement Plan capital is required to replace all light duty vehicles with electric vehicles by 2030. At this time, the Company is uncertain whether Mr. Jester's recommendation can be achieved based on the Vehicle Capital Replacement Plan's historical spending amounts. Finally, Mr. Jester's recommendation may require the Company to prioritize the replacement of light duty

vehicles with electric vehicles to the detriment of replacing heavy duty vehicles and equipment that is more directly relevant to performing electric system reliability work such as bucket trucks.

Q. Does the Company agree with Staff witness Hunter Hansen's recommendation, on pages 4 through 5 of his direct testimony, that the Commission reduce forecasted test year capital expenditures in the amount of $98,200 for Other Equipment?

A. Yes. The Company agrees.

Q. Is the Company withdrawing $98,200 in forecasted capital expenditures related to its Other Equipment projection from this case?

A. Yes. The Company is amending its forecasted capital expenditures for Other Equipment, Exhibit A-102 (QAG-3) as follows: reducing line 1 of Exhibit A-102 (QAG-3) from $670,191 to $571,991 for the 12 months ending April 30, 2027.

Q. Does the Company agree with Staff witness Hansen's recommendation, on pages 4 through 5 of his direct testimony, that the Commission reduce forecasted test year capital expenditures in the amount of $948,800 for Emergent Repairs?

A. Yes. The Company agrees.

Q. Is the Company withdrawing $948,800 in forecasted capital expenditures related to its Emergent Repairs projection from this case?

A. Yes. The Company is amending its forecasted capital expenditures for Emergent Repairs, Exhibit A-102 (QAG-3) as follows: reducing line 7 of Exhibit A-102 (QAG-3) from $2,705,793 to $1,756,993 for the 12 months ending April 30, 2027.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MS. HILLYER: Thank you, Your Honor and thank you Mr. Guinn. We haven't met yet, but I'm Holly Hillyer. I represent MEC, NRDC, Sierra Club, and CUB in this case, and I would like to talk to you a little bit about your rebuttal testimony and a couple of discovery responses that you recently sent to us regarding Douglas Jester's fleet electrification recommendation.

CROSS-EXAMINATION

BY MS. HILLYER:

Q. Do you have your rebuttal testimony in front of you?

A. Yes, I do.

Q. Okay. And were you able to get access to the SharePoint?

A. Yes.

Q. Okay. I apologize in advance. This is a fairly short set of questions, but I'm going to have you bounce around to a couple of different folders in the SharePoint. So first if you could go to the MNSC folder. There's a hearing exhibit folder, and then there's a folder in there with your name on it and then in that folder there is an Exhibit 40, MEC-40, which is your discovery response to MNSC CE-803. Do you see that?

A. Yes, I do.

Q. Okay in that response, you are estimating the rough cost of replacing the company's entire light duty fleet? Right? About 900 internal combustion engine trucks with electric vehicles.

A. Yes.
Q. Okay. Sorry. We're talking over each other.
A. Yes, that's correct.
Q. Thank you. And that estimate assumes replacing all light duty vehicles between 2027 and 2030, regardless of whether replacement is needed?
A. Yes.
Q. Okay. So leaving that behind for a moment, if you could go back out to the MNSC folder and navigate down to the Douglas Jester's folder, and it should be right on the top direct testimony of D Jester. Do you see that?
A. Yes.
Q. Okay. If you go to page 17 and take a look at lines 19 through 21.
A. Yes.
Q. All right. You beat me there. Do you see where it says the company should revise its target so that all light-duty vehicle replacements are fulfilled by electric vehicles no later than 2030?
A. Yes.
Q. Would you agree that Mr. Jester's recommendation pertains to all light-duty replacements? Light-duty vehicle replacements?
A. Yes.
Q. So, in other words would you agree that he's recommending the company replace light-duty vehicles with EVs as they

come due for replacements?
A. Yes.
Q. Okay. And returning to your discovery response, would you agree that your response addressed to the replacement of all light-duty vehicles, not just the ones that are due for replacement?
A. Yes.
Q. So is it fair to say that the -- the cost estimate that's in your discovery response is not addressing Mr. Jester's recommendation understanding that to mean only light-duty vehicles that are due for replacement?
A. Yes.
Q. Okay. If you could go back to the hearing exhibits folder and take a look at Exhibit MEC-41, which is your response to MNSC CE-0804, is the same also true of that response, which also assumes complete replacement by 2030?
A. Yes.
Q. Okay. And then I understand you have your rebuttal testimony in front of you, I believe, on page 5 is the page that you address Mr. Jester's recommendation. Is it fair to say that that's true of your rebuttal testimony also?
A. Yeah.
Q. Okay. Now returning to Exhibit MEC-40, which is in that hearing exhibits folder with your name on it, if you take a look at subpart B of your response where it says in its

next rate case filing, the company is willing to provide an assessment of whether fulfilling all light-duty vehicle replacements with electric vehicles by 2030 would require departing from the company's vehicle capital replacement plans historical spending levels. Do you see that?

A. Yes.

Q. Would you agree that that is addressing just vehicles that are due for replacement using that same phrasing that in Douglas Jester's recommendation, all light-duty vehicle replacements?

A. As drafted, it was addressing the replacement of all light-duty vehicles, whether they were scheduled for replacement or not.

Q. So the -- the assessment that the company was willing to provide was an assessment of replacing a light-duty vehicles?

A. Yes.

Q. Okay. Would the company agree to provide an assessment of fulfilling just the light-duty vehicles that are due for replacement with EVs between now and 2030?

A. Yes.

Q. Thank you.

MS. HILLYER: At this time, I'd like to move for the admission of Exhibit MEC-40, which is the company's response to discovery requests U-21870 MNSC CE-0803.

THE COURT: Are there any objections to the

admission of this exhibit.

Hearing none. Exhibit MEC-40 is admitted.

(At 2:28 p.m., Exhibit MEC-40 admitted)

MS. HILLYER: Thank you, and Mr. Guinn, I have no further questions for you. Thank you for your time today.

THE WITNESS: Thank you.

THE COURT: Is there anyone else who has any cross-examination for this witness.

Hearing none. Ms. Uitvlugt, do you have any questions for this witness?

MS. UITVLUGT: No, Your Honor.

THE COURT: All right. Mr. Guinn, you are excused. Thank you, sir.

THE WITNESS: Thank you.

THE COURT: Are there any objections to the admission of Exhibits A-101 through A-106?

Hearing none. Exhibits A-101 through A-106 are admitted.

(At 2:28 p.m., Exhibits A-101 through A-106 admitted)

THE COURT: All right that's -- that's it the names that were on the proposed schedule, if you will from Mr. Gensch's e-mail, are there any other witnesses scheduled for cross-examination who are present and for whom those interested in questioning are also present who

wish to proceed at this time?

All right. Then, why don't we go to some binding in. Mr. Kesky, are you with us?

MS. HARRIS: Your Honor?

THE COURT: Yes.

MS. HARRIS: The company would ask that instead of binding in the testimony of other parties in the middle of our cross-examination, if we wanted to bind in testimony, could we instead bind in the testimony of the witnesses of the company that were waived so we can keep as much of our witnesses together for the record.

THE COURT: Sure. We can do that.

All right. Ms. Uitvlugt?

MS. UITVLUGT: And before we began, Your Honor, can I double check with Mr. Gensch to make sure I'm binding in the right witnesses?

THE COURT: Sure. We'll go off the record for five minutes.

(Off the record at 2:31 p.m.)

(On the record at 2:35 p.m.)

THE COURT: All right. We're back on the record. I understand Consumers is going to bind in for some of their witnesses. Mr. Gensch, if we could go one at a time, please and please indicate for the record whether any of the testimony is confidential as well as whether any of the exhibits are confidential. Please

proceed.

MR. GENSCH: Thank you, Your Honor. Pursuant to agreement of the parties, Consumers Energy moves to bind in the testimony of Stacy H. Baker, her direct testimony consists of a cover page plus 120 pages of questions and answers. I would note there's a confidential version of her direct testimony and a redacted version that will be bound into the public record. Ms. Baker also had, also I will note that it is a revised redacted version of her direct testimony. Ms. Baker also had rebuttal testimony consisting of a cover page and 44 pages of questions and answers. Ms. Baker also sponsored a number of exhibits including Exhibit A-17, A-18, A-19, A-12 Schedule B-5.1, confidential Exhibit A-20, confidential Exhibit A-21, Exhibit A-22, revised confidential Exhibit A-23, A-24, A-25, revised confidential Exhibit A-26, Exhibit A-183, Exhibit A-184, Exhibit A-185, and Exhibit A-186.

THE COURT: All right. Are there any objections to the admission of this testimony or these exhibits appearing on the direct revised testimony and the rebuttal testimony of Stacy Baker is bound into the record with the confidential testimony being bound into the confidential record in Exhibits A-17 through A-19, A-22, A-24, A-25, and Exhibits A-183 through 186, are admitted to the public record. And Exhibits A-23 revised, and A-26 revised are admitted into the confidential record as our

exhibits A-20 and A-21.

(At 2:38 p.m., Exhibits A-17 through A-19, A-22, A-24, A-25, and Exhibits A-183 through 186 admitted to public record and Exhibits A-23 and A-26 admitted to confidential record)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REDACTED

REVISED DIRECT TESTIMONY

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Stacy H. Baker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. How long have you worked for Consumers Energy Company ("Consumers Energy" or the "Company") and what positions have you held?

A. I have worked for the Company for over 25 years in various individual contributor and leadership positions. The first nine years were in the Finance Department as an Accounting Analyst performing responsibilities to support Payroll and Accounts Payable and later as the Payroll Manager during the Systems, Applications, and Products in Data Processing ("SAP") implementation. Thereafter, I moved to the Information Technology ("IT") Department where I have held a number of positions including Enterprise Resource Planning ("ERP") Portfolio Manager, Director of Business Relationship Management – Corporate Services, and Executive Director of IT Business Technology – Corporate Services. In these roles I focused on technology supporting corporate areas of the Company and had IT departmental responsibility for the delivery and operation of IT applications for Finance, Human Resources ("HR"), Supply Chain, Legal and Government, Regulatory & Public Affairs. I am currently the Director of Technology Portfolio Office responsible for portfolio management of the Company's IT, Security, and Operational Technology ("OT") assets, project management office including agile services, project delivery organization, technology vendor management, and organizational change management. This includes the management of the IT long-term financial plan, administration of portfolio management, cloud financial management, development of testimony and exhibits, and supporting rate cases for the IT Department.

Q. Would you please state your educational background?

A. I earned a Bachelor of Science in Business Administration degree from Central Michigan University in December 1992 with a major in Accounting.

Q. Have you ever testified in any other proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I testified in the following cases:

- Case No. U-21308 – 2022 Gas Rate Case;
- Case No. U-21490 – 2023 Gas Rate Case; and
- Case No. U-21806 – 2024 Gas Rate Case.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to describe the Operating and Maintenance ("O&M") expenses and capital expenditures needed by the IT Department to maintain and secure existing IT and security systems and enable new capabilities and services to support safety, reliability, and resiliency. I also provide an overview of increasing threats in both Cyber Security and Physical Security areas, their evolution over time, and the changing regulatory landscape that necessitates increased O&M funding. These increases are essential for advancing cloud computing solutions, maturing security capabilities, and protecting the Company's technology and physical infrastructure.

Furthermore, my direct testimony provides an explanation of the Company's plans for deterring threats before they impact the Company and its customers, detecting malicious activity, and recovering quickly with minimal impact while complying with all regulations.

The benefits of increasing technology use for customers, and the Department's support of the Company's commitments outlined in the Integrated Resource Plan ("IRP") and Electric Distribution Infrastructure Investment Plan ("EDIIP"), will also be highlighted. Lastly, the importance of achieving full recovery of the requested expenses and expenditures to provide the best value to the Company's customers will be demonstrated.

Q. Please summarize the main portions of this testimony.

A. My direct testimony discusses the following:

- The importance to customers of digital investments and the role of IT to build and support those investments;
- Changes in the functions of the IT Department;
- Increasing and evolving cyber and physical threats;
- Leveraging increased cloud capabilities;
- Support for Operational O&M expense funding;
- A description of the investment, both O&M and capital, needed to keep the Company's systems secure, current, stable, and supporting new capabilities;
- Definition and rationale for the use of reduced Rough Order of Magnitude ("ROM") estimates and explanation of the difference from contingency requests;
- An explanation of the projects included in this rate case filing for the IT Department and their supporting business plans, as described in Confidential Exhibits A-20 (SHB-5) and A-21 (SHB-6);
- Company action to address previous Commission concerns, including:
  - Company total one time project cost across multiple years,
  - Total Company cost of ownership of each project beyond initial one-time project investment,
  - Recurring hard savings over the life of the investment, and

- Cost benefit ratio calculated by the Company's internal Business Planning System ("BPS");

- Individual project synopses and requests to support electric and customer plans;

- Individual project synopses and requests to support corporate functions crucial to running an efficient business;

- Individual IT project synopses with supporting, detailed exhibits for the Asset Refresh projects and the Application Currency projects;

- Individual IT project synopses with a supporting, detailed exhibit (Exhibit A-24 (SHB-9) for Enhancement projects, along with a detailed worklist of the enhancement work backlog found in Exhibit A-25 (SHB-10);

- Individual IT project synopses for the IT/Digital Foundations and Capabilities projects;

- Further information about and justification of several larger and more complex projects for which projected spending varies from amounts forecasted in Case No. U-21585, including the following projects:

  - Asset Refresh Program ("ARP")-Field Device Asset Management ("FDAM"),

  - ARP-Printer Asset Management ("PAM"),

  - ARP-Workstation Asset Management ("WAM"), and

  - SAP High-performance ANalytic Appliance ("HANA") Database Migration;

- Explanation of the changes to ARP – Cyber Security, subdividing it into the following new ARP projects relevant to this case:

  - ARP-Cyber-Common, and

  - ARP-Cyber-Electric;

- Explanation of the changes to ARP-Local Area Network, ARP-InfoBlox, and ARP-OT Electric, consolidating them into the following new ARP projects:

  - ARP-Network-Common; and

  - ARP-Network-Electric;

- Further information on the actual costs for projects which had disallowances in Case No. U-21585:

- IT Operations Management – Service Operations,
- Operational Technology – Service Management Upgrade,
- Software Asset – Service Management Upgrade, and
- SolarWinds Performance Monitoring Expansion Upgrade; and

- Further information about and justification of the more complex SAP S/4HANA Implementation project.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit A-17 (SHB-1)	Summary of Actual and Projected Information Technology Operations O&M Expense for the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027;
Exhibit A-18 (SHB-2)	Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance for the historical years 2024 - 13-month balance ending December 31, 2024, and for the projected years 2026 – 13-month balance ending April 30, 2027;
Exhibit A-19 (SHB-3)	Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027;

Exhibit A-12 (SHB-4)	Schedule B-5.1	Projected Capital Expenditures Information Technology Summary of Actual and Projected Electric and Common Capital Expenditures;
Confidential Exhibit A-20 (SHB-5)		Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses for the Years 2024, 2025, 2026, and 2027;
Confidential Exhibit A-21 (SHB-6)		Business Case Executive Summaries for Historical, Bridge Period, and Test Year Projects;
Exhibit A-22 (SHB-7)		Asset Refresh Programs Projected Electric and Common Capital Expenditures, For the Projected Year 2026 and Test Year Ending April 30, 2027, and For the Historical and Projected Years 2024 and 2025;
Confidential Exhibit A-23 (SHB-8)		Application Currency Programs Projected Electric and Common Capital and O&M Expenditures for the Years 2026, 2027, and Test Year 12 Months Ending April 30, 2027;
Exhibit A-24 (SHB-9)		Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis;

Exhibit A-25 (SHB-10)	Enhancement Worklist Detail for Years 2016 through October 21, 2024; and
Confidential Exhibit A-26 (SHB-11)	Projected 13-Month Average of IT S/4HANA Cloud Implementation Costs for the projected years 2026 – 13-month balance ending April 30, 2027.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

DESCRIPTION OF THE IT DEPARTMENT

Q. Please describe the purpose of the IT Department.

A. The purpose of the IT Department is to consistently provide and maintain reliable, secure, simple, and intuitive digital solutions and services that support the delivery of business objectives, including execution of the Company's IRP and EDIIP. Inherent in those objectives are the Company goals to provide exceptional service to its customers by supplying safe, reliable, affordable, clean, and equitable energy.

The IT Department strives to find the appropriate balance of value and cost in digital solutions. The Company's evolving and pragmatic approach to digital solutions supports many best practices, including:

- Executing work in an efficient and effective manner while remaining flexible as deliverables change by adopting agile frameworks, platforms, and product-centric operating models that allow the Company to adjust to changing demands on the IT system;
- Equipping coworkers with digital skills through training that enables them to deliver business value faster to ensure the Company meets customer expectations;
- Moving to cloud solutions where and when appropriate to reduce cost, improve security, and increase the speed of providing new capabilities;

- Treating data as an asset and deploying analytics on a larger scale for effective decision making, optimization of existing assets, and efficient investment prioritization;

- Deployment of a consistent asset management system and integrated control systems to reduce risk, optimize and digitize processes, and monitor the health of the system to identify necessary preventative maintenance that reduces waste and long-term costs;

- Ensuring customer data is safe and secure, their privacy is protected, and both critical technology assets as well as critical infrastructure assets are secure; and

- Managing security risks and mitigating associated threats.

Q. Have there been any changes to the IT functions that are new in Case No. U-21870?

A. Yes. The following changes have been integrated in my direct testimony and exhibits: (1) the Security Department is part of the IT Department and no longer represented by a separate witness; (2) the Company has integrated the analytics function (Analytics and Outreach) that was part of the Customer Interactions function into the IT Department; and (3) the Company has also integrated the analytics function that was a part of the Process, Analytics & Technology function, within Operations Performance, into the IT Department. These changes, new in Case No. U-21870, better centralize the Company's technology expenditures and expenses.

The Security Department capital expenditures and O&M expenses will continue to be represented as a separate business category in testimony and exhibits, while the Analytics expenses and expenditures will be represented in the IT business category for IT Operations O&M expense and the appropriate business category for capital expenditures and IT Investments O&M expense.

Q. Please describe the functions the IT Department performs.

A. The IT Department provides reliable, secure, and simple digital solutions and services to the Company's customers and internal business units. This includes identification,

delivery, operational support, and maintenance of both on-premise and cloud software solutions and computing and communications infrastructure and analytics to support customer safety and reliability. The IT Department also provides the day-to-day operational support for coworkers using technology, whether that technology is a desktop, laptop, or mobile device (e.g. ruggedized field device, tablet computer, cell phone, smartphone, or other handheld device).

The scope of the IT Department also includes OT. OT is the set of real-time industrial control systems that monitor and control the Company's critical electric infrastructure, such as the Electric Supervisory Control and Data Acquisition ("SCADA") systems.

Additionally, the scope of the IT Department includes Security. This includes emergency management, physical security, and cyber security. Security exists to deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal effect if or when a threat is successful in causing impact, and comply with all governmental and industry regulations. Security sets standards based on external threats and guides security work required by the IT and OT teams.

Q. How does technology support the Company's electric plans?

A. Technology is an integral part of all aspects of the Company's electric strategy from generation all the way to the customer. The Company is leading a clean energy transformation by accelerating the Company's exit from coal-fired generation while increasing electric reliability and resiliency for customers. To realize this plan, the Company needs to invest in new technology as the future of energy generation is increasingly more distributed and complex. As the Company increases investment in

demand response, energy efficiency, and grid modernization tools, these virtual "power plants" will help the Company reduce energy demand and manage customer load efficiently and effectively. The continued addition of solar energy sources, wind energy sources, and battery storage to the generation landscape will also require the utilization of technology systems to operate and manage them safely, effectively, and efficiently.

The Company's EDIIP is its roadmap to reliability that is driven by investments in a modern distribution system to safely deliver clean, affordable, and reliable power to customers throughout Michigan with a goal of fewer and shorter power outages. The Company's plan for a reliable and resilient modern electric grid requires technologies to support the electric devices, communications, and analytics for advanced capabilities like Volt-VAR Optimization and Conservation Voltage Reduction that advance energy efficiency and peak demand reduction. The Company's plan also relies on technology to enhance electric reliability and resiliency through Fault Location, Isolation, and Service Restoration, as well as enabling initiatives for Distributed Energy Resources, like solar and wind generation, and energy storage systems.

The use of technology is also essential to establishing data analysis techniques to understand, communicate, and engage with the Company's customers in a meaningful way; connecting with customers using their channel of choice; enhancing the Company's digital resources in response to growing customer feedback that they prefer "self-service" through digital channels; providing customers accurate, timely energy bills, and consistent payment processes; and offering options for customers to understand their energy consumption.

Q. What are some of the biggest challenges the IT Department currently faces?

A. A big challenge the IT Department currently faces is the integration and implementation of emerging technologies, data, and analytics needed to achieve the Company's goals described in the IRP and EDIIP. The Company relies heavily on accurate data and high performing systems that can handle higher transaction and data volumes. Customers depend on these same systems to report outages, receive timely information on the estimated time of restoration, and view the outage map including impacted areas. It is important that the Company achieve full recovery of requested expenses and expenditures to keep these systems updated with the latest security and maintenance patches while delivering new capabilities to help restore customers faster.

Another challenge is that security continues to be a significant risk area and challenge for utilities. Traditional physical security issues of protecting publicly accessible, geographically dispersed critical infrastructure are and will continue to be exacerbated as resources become more distributed. Cyber security concerns include privacy, data breaches, ransomware, ransom extortion, denial of service, and critical infrastructure attacks. For example, a February 7, 2024 Cybersecurity Advisory from the Cybersecurity and Infrastructure Security Agency ("CISA") states that the CISA, National Security Agency, and Federal Bureau of Investigation assess that People's Republic of China ("PRC") state-sponsored cyber actors are seeking to pre-position themselves on IT networks for disruptive or destructive cyberattacks against U.S. critical infrastructure in the event of a major crisis or conflict with the United States.[1] The U.S. authoring agencies have confirmed that the PRC state-sponsored cyber group known as Volt Typhoon has

[1] Available at https://www.sophos.com/en-us/content/state-of-ransomware.

compromised the IT environments of multiple critical infrastructure organizations - primarily in Communications, Energy, Transportation Systems, and Water and Wastewater Systems Sectors - in the continental and non-continental United States and its territories, including Guam.

While cyber security is no longer a new area, each year impacts from cyber security incidents increase. According to a 2024 Sophos report on the state of ransomware, while the rate of ransomware attacks dropped slightly since 2023, the average payout more than doubled from $1,500,000 in 2023 to $3,900,000 in 2024. In addition to ransomware, the Company must protect against data breaches and threats to critical infrastructure, cognizant of the North American Electric Reliability Corporation's ("NERC") ballooning Critical Infrastructure Protection ("CIP") compliance fine maximums and the federal government's warning regarding potential critical infrastructure attacks from Russia or China as part of global geo-political tensions. In this environment, it is more important than ever that utility security teams are prepared with plans that address the need for securing customer data, maintaining compliance, protecting customer privacy, and protecting the critical infrastructure that serves the Company's customers.

Q. Please further explain the current environment with respect to cyber threats facing utility companies.

A. Cyber threats are increasing. The most glaring example is ransomware as discussed above. These threats have increased, not only in their impact but also their level of sophistication. Criminal groups are profiting on ransomware, and it has become such a lucrative business that they now conduct cyberattacks in a more sophisticated manner with teams of people

who focus on an individual target. Such groups are more focused on Fortune 500 companies because of the potential for large ransom payments.

The Progress Software "MoveIT" extorsion event demonstrates this increase in sophistication. A zero-day vulnerability (a flaw in a system or device that is unknown and does not have a fix available to correct the flaw, rendering the system vulnerable) was used to compromise the data of hundreds of MoveIT customers across all industries. The ability to exploit zero-day vulnerabilities has historically only been within reach of nation-state actors, not criminal groups. The amount of money being made has allowed these groups to invest in finding such vulnerabilities and dramatically increased their capabilities. The Company sees, on average, several hundred cyber security events daily. This volume demands a robust security program with various layers of defense. No single tool, person, or process can protect the Company's assets 100% of the time; therefore, the Company must rely on multiple lines of defense to meet these challenges.

Beyond ransomware, nation-state actors have a strong interest in United States critical infrastructure. The federal government has repeatedly called out this risk and has been imploring critical infrastructure owners to increase their capabilities. On July 28, 2021, the Biden Administration released a memo titled "National Security Memorandum on Improving Cybersecurity for Critical Infrastructure Control Systems" ("July 28 Memo").[2] The implications of the National Security Memo are clear.

First, the threat to critical infrastructure is real and no longer theoretical. Even the Company has seen intrusion attempts from nation-state level actors. The July 28 Memo provided that "[t]he cybersecurity threats posed to the systems that control and operate the

[2] Available at https://bidenwhitehouse.archives.gov/briefing-room/statements-releases/2021/07/28/national-security-memorandum-on-improving-cybersecurity-for-critical-infrastructure-control-systems/.

critical infrastructure on which we all depend are among the most significant and growing issues confronting our Nation."

Second, cyber security of critical infrastructure is a national security issue and priority. The July 28 Memo explained that "[t]he degradation, destruction, or malfunction of systems that control this infrastructure could cause significant harm to the national and economic security of the United States." Utilities have had strong cyber security programs, and the Company is no different. However, by calling out cyber security of critical infrastructure as a national security issue, the Biden Administration signaled that the Company, as an owner of critical infrastructure, should meet an even higher standard moving forward. The National Security Memo suggested that utilities need to have capabilities matching those of the top government agencies and contractors. This increased expectation will take time to develop and increased funding to achieve.

Third, as ordered by the Biden Administration, the CISA has established Cross Sector Cybersecurity Performance Goals, which signals the federal government's interest in gaining further assurances that owners and operators of critical infrastructure are meeting the expectations set forth in the memo. The Company expects this to include new, mandatory regulatory standards for electric.

As for the Trump Administration, it recently issued an executive order suggesting that it may shift responsibility for investments in cybersecurity and other critical infrastructure to state and local governments. In doing so, the White House recognized that "[c]itizens are the immediate beneficiaries of sound local decisions and investments designed to address risks, including cyber attacks, wildfires, hurricanes, and space

weather."[3] Thus, the White House continues to support further investment in cybersecurity, even if state and local governments are ultimately asked to assume more responsibility. The executive order directed federal officials to reevaluate national critical infrastructure policy, including several National Security memorandums, but the July 28 Memo was not on the list of memorandums being reviewed.

Q. Please describe how physical threats are increasing or evolving.

A. Cyber security receives much of the national headlines because it is a relatively new risk and does not require physical proximity to execute an attack. However, physical security risks are still extremely relevant in the critical infrastructure space, and they continue to evolve. In the past year, there have been several incidents that pose risks to the stability of the electric grid. These include theft, equipment damage, vandalism, and intentional gunfire aimed at disrupting the grid.

- **Copper Theft**: Thieves target substations, transformers, and other electrical infrastructure due to the high resale value of copper, which causes substantial damage and disrupts power supply.
- **Transformer Damage**: Damaged transformers can leak oil, posing environmental hazards. Tampering with high-voltage equipment can also lead to explosions or fires.
- **Gunfire Incidents**: In the mid-Michigan area, there have been incidents where gunfire was aimed at critical electric infrastructure, intending to disrupt service.

These types of incident present challenges in maintaining a reliable and safe electricity supply.

[3] Presidential Actions, *Achieving Efficiency Through State and Local Preparedness*, THE WHITE HOUSE (March 29, 2025), https://www.whitehouse.gov/presidential-actions/2025/03/achieving-efficiency-through-state-and-local-preparedness/.

Q. What physical security challenges are you experiencing in securing critical infrastructure assets?

A. The very nature of certain utility assets makes them very challenging to secure. Large assets such as a headquarters building or power plants can be secured using traditional physical security measures such as video cameras, card access, fencing, locks, keys, gates, and guards. The smaller, more distributed assets are significantly more challenging to secure. Placing guards at each asset would be untenable from a cost perspective. Technology solutions have historically been challenging because of limited feature sets (enhancements and capabilities) and network capacity at many of these remote locations. These limitations have led utilities to implement basic physical protections and accept remaining risk. Responses to security issues in these environments are, therefore, reactive and have become insufficient. These factors have made these critical assets soft targets to those who would do harm intentionally and attractive for opportunistic crimes. A shift to a more proactive approach will minimize the impacts to customers from outage, safety, and cost perspectives. The Company continues to be proactive in its approach to better protect its assets and increase safety.

Q. What is changing in the regulatory landscape?

A. The current cyber and physical regulatory landscape is highly uncertain. The current administration aims to reduce regulatory oversight, but their position on cyber and physical security and its national security implications remains unclear. The recent executive order indicates that the administration may propose more state control over these areas. Regardless, the Company anticipates a continued push for more cyber incident reporting and mandatory standards in electric distribution, whether driven by federal or state

authorities. The industry is expecting additional mandatory cyber security standards across the regulatory landscape.

Q. Has the work required to meet cyber security regulations and requirements increased in recent years?

A. Yes. The Company has new NERC/CIP requirements for electric systems. While gas focused, the TSA (Transportation Security Administration) security directives also affect the Company's corporate systems, which are a part of this case.

Q. Do cyber security requirements increase the frequency of IT patching and upgrades?

A. Yes. To address changing security threats and vulnerabilities, vendors regularly release security fixes or "patches" to their products. The increased volume of threats to digital assets heightens the need to keep systems current, and timely security patching is a key control for any security program. Technology vendors establish timelines for versions of their product they no longer support or no longer provide security updates or patches for. Where the Company may have had more discretion in the past to defer upgrades, it now must ensure the appropriate upgrade or replacement frequency to meet security requirements. Patching analysis, patch application, and patch tracking activities are all considered IT Operations O&M expenses. The Company focuses on mitigating exposure to "Known Exploited Vulnerabilities" that the Cybersecurity and Infrastructure Security Agency has confirmed have been used to breach other companies' IT systems in the past. Reducing vulnerabilities requires timely patching, as well as upgrades and replacements to IT software and systems. The operational expenses related to security are important for the protection of Company assets and customer information.

Q. Please explain why the Company is proposing to use more Software as a Service ("SaaS") based products.

A. SaaS based offerings are often the only option for certain technology services/vendors. For those that do also have on-premise options, many are stating that they will not be updated as quickly or may lack certain capabilities of their cloud counterparts. Vendors are making this shift for many reasons. First, as technology moves more and more to the cloud, security services need to adapt as well. Second, vendors can much more quickly build new capabilities for customers in a cloud-based scenario where they control all the underlying hardware and infrastructure. Finally, the massive scale of security data requires much more flexibility which the cloud offers, and on-premise does not.

In addition to the industry drivers, there are benefits to both the Company and customers. More SaaS means fewer large capital outlays for large hardware purchases, vendor integrations, and less asset refresh cost. The Company anticipates fewer large capital projects in its future year planning for cyber security as capital requests have reduced, while physical security requests are increasing. Finally, using SaaS allows the Company to receive the best security capability available and allows vendors to adapt to changes much more quickly than on-premise solutions.

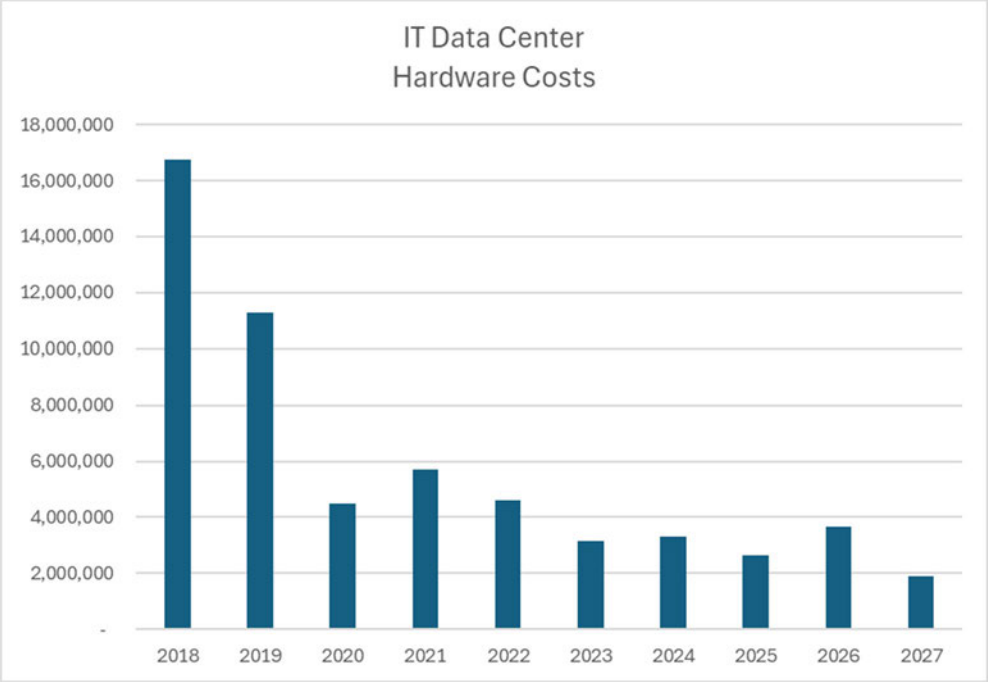
Q. Is the Company migrating to the cloud and what are the advantages of leveraging increased cloud capabilities?

A. Yes, the Company is migrating most of its IT data center to cloud-based services. Leveraging increased cloud capabilities offers several advantages, including the ability to scale capacity, pay only for resources that are used, avoid capital investment and O&M

expense for hardware and maintenance, enhance security, and employ built-in backup and recovery solutions.

First, cloud capabilities offer scalability, enabling the Company to easily adjust their computing resources based on demand. This allows the Company to increase or decrease capacity as needed, unlike traditional data centers that would require longer implementation times. For example, during peak periods like storm response, the Company can quickly scale up resources to handle increased traffic. Conversely, during off-peak periods, cloud resources can be reduced to optimize costs.

Second, cloud capabilities also offer cost efficiencies by only paying for the resources that are used. It reduces the Company's capital expenditures in physical hardware and the associated ongoing maintenance costs, as well as the cost of a physical location. The Digital-Hybrid Cloud and Data Center Migration project, which began in 2022, has enabled the Company to avoid the capital investment for IT data center hardware asset refresh based on a five- to seven-year refresh cycle, as shown in the table below. This initiative includes migrating or retiring applications out of existing Company and co-location data centers into cloud services.



Third, cloud capabilities offer advance security features and regular updates to protect sensitive data, ensuring compliance with industry standards and regulations.

Fourth, the Company's owned data center is aging and beginning to have challenges with operational stability. Moving to the cloud allows the Company to avoid the large capital expense of building a new data center.

Finally, cloud capabilities offer reliable backup and disaster recovery solutions through redundant infrastructure to ensure high availability and reliability, minimizing downtime and providing consistent access to services.

Q. How does the Company prioritize, balance, and manage the delivery of new capabilities that support the IRP and EDIIP with operational work that includes meeting the security requirements described above?

A. The Company's critical security and operational fixes are given priority over new capabilities to ensure safe, secure, and reliable operation of its digital assets. There is a high demand for new and enhanced technology capabilities across the Company. New

investments are prioritized based on an evaluation of the benefits, costs, customer value, and necessity to Company goals through a series of reviews by cross-functional business teams. The highest-ranking projects are approved through the Company's budget and rate case processes and ultimately implemented.

Q. What business categories has the Company defined in the IT Organization?

A. The Company has defined the following business categories in the IT Department supporting the IRP, EDIIP, and customer offerings in this case: (1) Electric; (2) Electric & Gas Shared; (3) Corporate; (4) Customer; (5) IT/Digital Foundation; and (6) Security. These business categories are used to group investment spending in my exhibits to better connect rate case filings with the Company's plans. I will describe each of the business categories later in my testimony.

IT OPERATIONS O&M EXPENSES—MAINTAIN AND OPERATE EXISTING ASSETS

Q. What is IT Operations O&M expense for IT?

A. The Company uses IT Operations O&M expense to provide the required level of operational support, reliability, and security for technology investments; maintenance for security facilities and systems to ensure system reliability, vulnerability assessments, and penetration tests; and fulfillment of all state and federal laws and regulations, perimeter protection, guards, card access, cameras, executive protection, and investigative services. IT Operations O&M expenses include fixed and variable ongoing costs. Fixed costs include software vendor maintenance agreements, cloud subscription contracts, annual license contracts, and application or appliance support through managed services contracts. Software and cloud solution vendors typically increase these fixed costs on an annual basis. Variable costs include labor for equipment monitoring, break/fix activity, maintenance

activity, disaster recovery, security improvements, software patching, and cloud usage costs. Operations costs also include physical security site assessments, vulnerability and penetration test remediation, additional guard support, system break/fix or maintenance activity, privacy program maturity, staffing support to meet emerging regulatory laws and regulations, and additional security system improvements. The activities associated with the fixed and variable costs are required to keep the Company's digital, information, and physical assets protected and performing at sufficient levels. The Company's customers benefit from the system stability and reliability that result from the activities funded by IT Operations O&M expense. These activities include emergency response, 24/7 billing, payment and usage services, contact center support, new service installations, and various other digital offerings, as well as physical and cyber security activities. Any unrecovered IT Operations O&M cannot be recovered in future rate case filings, which is why any disallowance could impede the Company's ability to maintain and secure its facilities and systems.

Q. Please describe the operational work required to keep information and physical assets protected from cyber threats.

A. There is a variety of operational work required to keep information and physical assets protected from cyber threats. First, regarding information assets, security tools must be kept functional when they are called on to protect the technology vital to serving the Company's customers. This technology includes software to collect logs, scan for vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second, IT resiliency must be kept up to date ensuring backup data and redundant infrastructure are in place in the event of a cyber intrusion. Third, as described previously, systems must be

patched on a regular basis in accordance with security requirements. Vendors regularly release security updates that must be tested to ensure these updates do not introduce negative impacts to Company-specific configurations when deployed. Fourth, as cyber security standards and requirements change, IT teams must implement the appropriate corresponding technical changes on existing systems to ensure Company assets remain secure. These requirements evolve and adapt as threats change in our environment. Security regularly reviews and updates physical and cyber security standards to maintain the appropriate posture with various industry frameworks, as well as compliance with cyber security regulations. This includes the technical requirements for IT to follow, which increases operational costs while continuing to best protect Company assets

Regarding physical assets and employee safety, first, routine assessments must be performed on all assets and facilities to ensure proper maintenance is performed and security protections are properly placed including perimeter protection, cameras, and card readers for facility access. Second, additional security support is needed for employees when threats are present near field project work, storm restoration activities, or Company sponsored public events or forums. Third, additional security guard support is needed at facilities on an ad hoc basis (based on intelligence collected from facilities or crews, threats of violence against the Company, increased protest activity as seen in 2020, increased contractor traffic, and potential employee issues) to ensure the safety of employees and any visitors to the Company's facilities.

Q. What value will customers receive for the projected test year O&M expenses?

A. Foundational technologies, such as infrastructure, user devices, and collaboration tools, play a crucial role in supporting the systems that deliver services to the Company's customers.

Infrastructure includes physical and virtual systems that support all Company operations. These systems are essential for running critical applications, managing data, and maintaining communication that ensure efficient and reliable service to customers. User devices provide workers access to real-time data, help manage work, and facilitate communication to serve customers. Collaboration tools enable workers to collaborate effectively, address issues efficiently, and share information to serve customers.

Further, foundational technology systems support predictive analytics and machine learning algorithms that can forecast demand and identify potential issues before they become critical, allowing for proactive maintenance and response. Additionally, these systems support the integration of renewable energy sources, enabling a more sustainable energy supply.

Customers are required to provide certain types of data as part of the service provided to them and want to know that the Company has a world class cyber security program working to protect data provided. Data breaches can cause identity theft, fraudulent charges, and time lost addressing related associated impacts. Beyond data breaches, customers also expect their data to be handled properly and only for the purposes intended. The discipline which addresses these concerns is broadly referred to as privacy, which is also within the corporate responsibility of the IT Department. In addition to data-related concerns, customers expect the Company's core services to be available 24/7.

This is relevant on both the corporate and operational sides of the business. A ransomware attack would limit the service the Company can provide to customers and could lead to delays in resolving issues, obtaining service, outages, or significant safety concerns. An attack against the Company's operational systems could lead to a protracted loss of electricity or natural gas service for large portions of the service territory. Interruption of gas or electric service due to a cyberattack is not acceptable, and customers expect the utility to have all the protections necessary to ensure this does not occur.

In addition, physical security measures are essential in protecting the infrastructure that delivers electricity. This includes securing substations, power plants, and transmission lines from physical threats such as vandalism, theft, and natural disasters. Implementing robust physical security protocols, such as surveillance systems, access control, and perimeter security, helps safeguard these critical assets. By integrating physical security with technological systems, the Company can create a comprehensive approach to protecting the electrical grid and ensuring uninterrupted service to its customers.

Together, these foundational technologies and cyber and physical security measures ensure that electricity is delivered efficiently, reliably, and safely to customers.

Q. Please describe Exhibit A-17 (SHB-1).

A. Exhibit A-17 (SHB-1) is a Summary of Actual and Projected IT Operations O&M Expense for the Years 2024, 2025, 2026, and 12 months ending April 30, 2027. Page 1 summarizes the electric allocation of actual and projected IT Department operational expenses. Specifically:

- Column (a) provides the IT Operations O&M expense category;
- Column (b) identifies the total 2024 historical IT Operations O&M expense as $51,403,000;

- Column (c) identifies the total 2025 projected IT Operations O&M expense as $58,460,000;
- Column (d) identifies the total 2026 projected IT Operations O&M expense as $66,327,000;
- Column (e) identifies the total projected IT Operations O&M expense for the 4 months ending April 30, 2027 as $22,441,000;
- Column (f) identifies the total projected IT Operations O&M expense for the Test Year as $66,659,000; and
- "Labor" line items include employee labor; "Contracts" line items include hardware and software licenses and maintenance, and software subscriptions; "Material" line items include individual computer peripherals, tools, supplies, and replacements for failed components such as hard drives; and "Contractor" line items include staff augmentation, the Company's managed services contracts, and other contracted services. "Non-Labor Other" line items include employee training, wireless plans, and supplies.

Page 2 presents the amounts of the projected IT Operations O&M expenses that were developed by applying an inflation rate to the historical O&M expense. Specifically:

- Column (a) describes the categorical expense;
- Column (b) provides the historical IT Operations O&M expense;
- Column (c) provides the historical amount that an inflation rate was applied to;
- Columns (d), (f), and (h) provide the inflation increases for each respective period;
- Columns (e) and (g) provide the amount that an inflation rate was applied for 2025 and 2026, respectively;
- Column (i) includes amounts that were projected using other methods; and
- Column (j) provides the projected test year IT Operations O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please describe the Other Adjustments in Exhibit A-17 (SHB-1), page 2, column (i).

A. IT does not apply inflation in all categorical spend projections for IT Operations O&M expense. Labor is the only categorical spend projection that includes a merit increase based

on the inflation rate. Inflation is not used to project any other categorical spend projections for IT Operations O&M expense. Future contract expenses reflect current commitments to increase payments under existing contracts, as well as the addition of new contracts needed for ongoing and new project work taking place before or during the test year. Material and Non-labor Other are projected based on historical spend and known adjustments for employee training needs, wireless plans, and supplies.

Q. Please describe the projected IT Department IT Operations O&M expense for 2025, as reflected in Exhibit A-17 (SHB-1).

A. The IT Operations O&M expense in 2025 of $58,460,000 is projected to be an increase over 2024, which is $47,095,000 for IT and $11,365,000 for Security. The reason for the increase in 2025 is the result of organizational changes and the necessity to fund continued investment in programs to sustain and improve system reliability; to maintain, improve, and secure critical enterprise systems that support the Company's IRP and EDIIP; and to prevent obsolescence and risk to business operations offset by cost-saving measures. Key drivers for the change from 2024 to 2025 for IT include: (1) net labor increased based on merit increases ($0.19 million) – transfer of website from Customer Operations and analytics resources from Customer Interactions and Operations Performance ($0.56 million) to IT, increase in resources supporting grid and electric asset management ($0.33 million), backfill of resources supporting analytics ($0.5 million), and offset by move of network resources to Security ($0.2 million); (2) increase material costs ($0.65 million); (3) increase in contractor ($1.3 million), which a portion ($0.12 million) is based on the transfer of website contractors costs from Customer Interactions; (4) net increase in contracts for cloud subscriptions and license and maintenance agreements due to cost

optimization efforts offset by annual increases ($2.1 million); and (5) a decrease in Non-Labor Other ($0.58 million) based on reduction in business expenses.

Key drivers for the change from 2024 to 2025 for Security include: (1) labor increased based on merit increases ($0.08 million) and increase for resources to support the Fusion Center and move of network resources from IT to Security ($0.71 million); (2) net increase in contracts for cloud subscriptions and license and maintenance agreements ($1.2 million) including reductions in MS Azure costs offset by an increase in cloud security platform; (3) increase in contractor ($0.59 million) based on reduction in Physical Security contractors; and (4) decrease in Non-Labor Other ($0.5 million) based on reduction in business expenses.

Q. Please describe the projected IT Department IT Operations O&M expense for 2026, as reflected in Exhibit A-17 (SHB-1).

A. The IT Operations O&M expense in 2026 of $66,327,000 is projected to be an increase over 2025, which is $54,964,000 for IT and $11,362,000 for Security. The reason the Company is projecting an increase in 2026 is the necessity to fund continued investment in programs to sustain and improve customer reliability as the Company continues investing to maintain, improve, and secure critical enterprise systems and migrate applications to the cloud. Known increases that are projected for IT include: (1) net labor increase due to merit increase ($0.23 million) offset by resource efficiencies; and (2) increase in cloud subscriptions and license and maintenance agreements ($7.9 million) including costs related to the Genesys Cloud Migration, Standard Work Plan, and Digital-Hybrid Cloud and Data Center Migration projects and additional increases offset by cost optimization efforts to keep costs flat.

Key drivers for the change from 2025 to 2026 for Security include: (1) net labor increase based on merit increases ($0.09 million) offset by resource efficiencies; and (2) no change in contracts for cloud subscriptions and license and maintenance agreements due to planned cost optimization efforts to offset increases.

Q. Please describe the projected IT Department IT Operations O&M expense for the test year, as reflected in Exhibit A-17 (SHB-1).

A. The IT Operations O&M expense in the test year of $66,659,000 is projected to be an increase over 2026, which is $55,297,000 for IT and $11,362,000 for Security. The reason the Company is projecting an increase in the test year is the necessity to fund continued investment in programs to sustain and improve customer reliability as the Company continues investing to maintain, improve, and secure critical enterprise systems and migrate applications to the cloud. Known increases that are projected for IT include: (1) labor is flat due to merit increase ($0.08 million) offset by resource efficiencies; and (2) increase in cloud subscriptions and license and maintenance agreements ($0.34 million), including costs related to the Digital-Hybrid Cloud and Data Center Migration projects.

Key drivers for the change from 2026 to the test year for Security include: (1) labor increase based on merit increases ($0.03million) offset by resource efficiencies, and (2) no change in contracts for cloud subscriptions and license and maintenance agreements due to planned cost optimization efforts to offset increases.

Q. What does the Company's IT Operations O&M expense include?

A. As described earlier, IT Operations O&M expense is made up of several components, such as labor, business expenses, material costs, contractor support, and vendor licensing and maintenance contracts.

"Labor" includes operational and governance costs for the IT employees who perform activities such as maintaining and supporting capital assets; disaster recovery and business continuity planning and testing; cyber security analysis and mitigation, such as security patching; and implementing performance measures to control IT costs and ensure compliance. These activities are variable and dependent on the outcome of risk analyses and other factors.

"Non-Labor Other" includes costs such as: business expense, employee training, wireless plans, and supplies. These costs are variable and dependent on the needs of the organization.

"Material" includes costs such as individual computer peripherals, tools, supplies, and replacing failed components such as hard drives. These costs are variable and dependent on the needs of the organization.

"Contractor" are costs of managed services and third parties that maintain and operate the Company's IT assets. Similar to "Labor," the activities include system monitoring, system break/fix, disaster recovery activities, system analysis, and patching. The use of third parties to maintain and operate the Company's IT assets provides value by helping to control labor costs, offering up to 24/7/365 support, and providing increased access to specialized IT expertise.

Contracts, including "On-Premise Contracts" and "Cloud Subscriptions," reflect the Company's IT operations expenses for contracts with vendors who provide software and hardware licensing, support, and maintenance services so systems remain safe from mechanical and software failures and cyber intrusions. Lapses in licensing, support, or maintenance coverage caused by financial constraints would expose the Company to unfavorable security and operational risks or issues.

The Company relies heavily on vendors and their products to run the utility's digital systems and, as a result, the number of contracts and the corresponding costs are a significant piece of the total IT Operations costs.

Q. Is the method used by the Company to project IT Operations O&M an accurate and prudent approach?

A. Yes, the method used by the Company to project IT Operations O&M expenses in Exhibit A-17 (SHB-1) is the most accurate method. The Company's approach uses a detailed analysis of known fixed and variable expenses for the test year. These include increases that result from new investments and assets tied to growth in digital, new cyber security regulations and requirements, and outcomes of cost optimization efforts. By using known and expected expenses that are coupled with the evolving digital landscape, the projection is the best representation of the Company's required IT Operations O&M expenses in the test year.

Q. Please describe Exhibit A-18 (SHB-2).

A. Exhibit A-18 (SHB-2) is the IT Cloud Computing Prepaid Balance for Electric and Common operations for the historical 13 months ending December 31, 2024 and the

projected 13 months ending April 30, 2027. It provides a summary of the electric allocation of actual and projected IT Department operational expenditures. Specifically:

- Column (a) provides the prepaid balance category;
- Columns (b) through (n) provide each month's ending IT cloud computing prepaid balance; and
- Column (o) provides the 13-month average of columns (b) through (n).

Q. Please describe the purpose of Exhibit A-18 (SHB-2).

A. The move to utilize cloud computing is resulting in an increase in prepaids associated with cloud computing subscriptions and implementation costs. The Company has identified cloud computing as a viable alternative for several technology solutions, which are described in more detail for the associated projects below. To support the adoption of cloud computing, the Company is adjusting working capital to reflect projections for cloud computing subscriptions and implementation costs. Cloud computing costs are projected based on existing cloud computing subscription agreements plus projected new cloud computing costs based on planned implementations. This working capital adjustment is provided by Company witness Patrick D. Daly on Exhibit A-12 (PDD-34), Schedule B-4.

IT INVESTMENTS O&M EXPENSES—MAINTAIN A CURRENT SYSTEM AND BUILD NEW CAPABILITIES

Q. How is IT Investments O&M for IT used by the Company?

A. IT Investments O&M is used by the Company to fund the O&M portion of upgrade projects, asset refresh projects, and technology investments that are needed to provide new capabilities for internal business units, security operations, and customers.

Q. Please describe the importance of upgrading IT systems for cyber security requirements and operational stability.

A. Upgrading applications, appliances, operating systems, database management systems, and security devices, such as cameras and card readers, are essential to delivering safe, reliable, affordable, clean, and equitable electricity to the Company's customers. Implementing current versions of technology enables the Company to operate secure and stable systems, remediate security vulnerabilities, keep customer and Company data secure, maintain vendor support, address defects that impair stability and functionality, and address version interdependencies and compatibility between systems.

Q. What cyber security risks could occur if the Company does not keep its systems upgraded?

A. Technologies and security devices that are not upgraded are often no longer supported by vendors, which increases security risk as well as system operations risk, as security patches are regularly released by vendors based on known vulnerabilities. Security patches are typically not produced for products no longer supported by the vendor, referred to as end-of-life products; therefore, an end-of-life product may have known vulnerabilities and no method to remediate the risk. This increases the risk of a significant cyber event impacting Company operations, data, and services to its customers.

Q. How does the Company determine which systems need to be upgraded?

A. While the Company's preferred upgrade strategy is to stay, at most, one version behind the vendor's currently available version, the Company considers multiple factors to determine when upgrades are needed. These include application criticality to business and customer operations, severity of existing vulnerabilities and operational risk, operational impacts of

performing the upgrade, ability to defer, resource availability, organizational change impact, and cost. Deferring an application upgrade for too long has the potential to increase the overall cost of the upgrade since the larger number of differences between versions generally adds complexity and cost to an upgrade effort.

Until recently, the Company has lacked funds to maintain and keep systems current. This led to technical obsolescence, and the Company is in a position of playing catch-up, adding risk that a significant cyber security or technical issue might not be remediated or mitigated, which would cause direct impact to Company operations, its customers, or both. The Company prioritizes operational support over new investments when resources are limited, thus putting the IRP and EDIIP at risk when important systems cannot be kept current with available resources.

Q. Please describe Exhibit A-19 (SHB-3).

A. Exhibit A-19 (SHB-3) is a Summary of Actual and Projected IT Investments O&M Expenses for the Years 2024, 2025, 2026, and the 12 months ending April 30, 2027. Page 1 provides a summary of the gas allocation of actual and projected IT Investments O&M expenditures. Specifically:

- Column (a) provides the IT Investments O&M expense category;
- Column (b) identifies the 2024 historical IT Investments O&M expense as $8,536,000;
- Column (c) identifies the 2025 projected IT Investments O&M expense as $13,174,000;
- Column (d) identifies the 2026 projected IT Investments O&M expense as $26,169,000;
- Column (e) identifies the 4 months ending April 30, 2027 projected IT Investments O&M expense as $8,857,000;

- Column (f) identifies the Test Year projected IT Investments O&M expense as $26,303,000;

- For Investments Planning expense, "Labor" line items include employee labor, and "Contracts" line items include hardware and software licenses and maintenance, staff augmentation, and other contracted services; and

- For Investments expense, "Labor" line items include employee labor; "Software" line items include software licenses and maintenance contracts; "Material" line items include hardware purchases and maintenance contracts; "Contractor Costs" line items include staff augmentation, managed services, and other contracted services; "Non-Labor Overhead" line items include overheads; and "Non-Labor Others" line items include pension expense, administrative/general expense, Allowance for Funds Used During Construction ("AFUDC"), and business expenses.

Page 2 presents the amounts of the projected IT Investments O&M expenses that were developed by applying an inflation rate to historical O&M expense. Specifically:

- Column (a) is a description of the categorical expense;

- Column (b) provides the historical IT Investments O&M expense;

- Column (c) provides the historical amount that an inflation rate was applied to;

- Columns (d), (f), and (h) provide the inflation increases for each respective period;

- Columns (e) and (g) provide the amount that an inflation rate was applied for 2025 and 2026, respectively;

- Column (i) includes amounts that were projected using other methods; and

- Column (j) provides the projected test year IT Investments O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please describe the Other Adjustments indicated in Exhibit A-19 (SHB-3), page 2.

A. IT does not apply inflation for categorical spend projections for Investments Planning expense. The investments planning projection is adjusted by $362,000 for IT and $4,000 for Security for anticipated decreases in the test year for investments planning activities that directly support business case development and cost estimate refinement for projects

that support the IRP, EDIIP, and other Company long-term plans. Inflation is also not used to project future IT Investments O&M expense. The other adjustments for IT Investments O&M expense of $17,317,000 for IT and $816,000 for Security are based solely on expected project costs for the test year as compared to the historical period, as detailed later in my testimony and in Confidential Exhibit A-20 (SHB-5).

Q. Are the preliminary project stage activities that must be part of IT Investments O&M expense per Financial Accounting Standards Board ("FASB") guidelines important in technology investment projects?

A. Yes. The preliminary project stage activities are essential to ensure the Company makes prudent investments in technology that benefits customers. The activities cover much of the work included in the Company's investment planning for IT projects. Investment planning activities gather information that is required by the MPSC in Case No. U-18238 as part of the rate case filing requirements for IT and OT.

Q. Is the investment planning activity speculative?

A. No, it is not speculative. Investment planning is a pragmatic process that results in documented technology investment details. The process documentation includes: a project description and description of system functionality, project timelines including expected implementation date and spending plans, project benefits, a description of alternatives considered and rationale behind the decision, and cost benefit ratio, which were required by the MPSC in Case No. U-18238. Other important activities of investment planning are: identifying high-level business requirements, determining whether the functionality needed is already present in the Company's IT environment, identifying performance and security requirements, working with software vendors and cloud solution providers to

demonstrate the effectiveness and security of their products and services, and developing the business case with project costs and benefits to confirm whether a proposed project should be approved for development and implementation.

During the investment planning phase, the Company spends the necessary time on up-front planning and due diligence for the technology investment. As an example, to maintain the reliability and safety of the Company's field dispatch communications, the Company needed to replace the aging core radio system infrastructure. The Company spent time on up-front planning for the 800 MHz Modernization upgrade project to build and confirm the scope, estimates, and alternatives. Investment planning is time needed to better understand the vendor solution and organize the work. Investment planning is based on key outcomes and fact-gathering to ensure it is not merely speculative.

Q. Should the Company be allowed recovery for the planning expense tied to technology investments?

A. Yes, the Company should be allowed recovery for this up-front planning activity. This work is required by the MPSC for technology investment, and for good reason. It is in the best interest of the Company's customers that the Company perform these investment planning activities to ensure potential investments provide sufficient value to justify the expense. The Company considers many ideas, but not all are feasible or even warrant investment planning. Critical as these expenses are, the Company does strive to minimize planning expenses; only those potential investments with the highest expected value even reach the planning phase. This reasonable and prudent work has associated costs and is required by the MPSC for technology investment planning. Accordingly, the Company should receive recovery for this required expense.

Q. Would it be more accurate to use a different method to project the Company's IT Investments O&M expenses?

A. No. The level of IT Investments O&M expense is closely coupled with the projected capital expenditures for IT and the upgrade and replacement cycles for existing assets. To fully and appropriately execute plans to spend the capital that has been deemed prudent to deliver value to its customers, keep its technology assets as current and secure as reasonably possible, and adhere to the FASB ASC 350-40 guideline for project activities that should be expensed, the Company requires the specific and forward-looking IT Investments O&M requested for the Test Year period. Other methods such as a historical average, which would be lower than the requested amount in this case, would not allow the Company to keep its systems current for security and reliability and make necessary and prudent capital expenditures to achieve the outcomes of the IRP, EDIIP, and improve customer service. Additionally, the Company projects an increase in cloud solutions, which often have a higher level of IT Investments O&M than projects in earlier years.

INVESTMENTS CAPITAL EXPENDITURES

Q. Please describe the capital expenditures shown on Exhibit A-12 (SHB-4), Schedule B-5.1.

A. Exhibit A-12 (SHB-4), Schedule B-5.1, identifies the electric allocation of actual and projected capital expenditures to procure, install, and implement the software and infrastructure described in my testimony to meet business requirements. Specifically:

- Column (a) provides the business category designation for the capital expenditures:
  - Corporate;
  - Customer;

- Electric;
- Electric & Gas Shared;
- IT/Digital Foundation; and
- Security.

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  - Column (b) identifies the 2024 historical year capital expenditures as $44,023,000;
  - Column (c) identifies the 12 months ending December 31, 2025 projected bridge year capital expenditures as $52,118,000;
  - Column (d) identifies the 4 months ending April 30, 2026 projected bridge year capital expenditures as $28,191,000;
  - Column (e) identifies the 16 months ending April 30, 2026 projected bridge year capital expenditures as $80,310,000; and
  - Column (f) identifies the 12 months ending April 30, 2027 projected test year capital expenditures of $77,719,000.
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  - Column (b) identifies the 4 months ending April 30, 2025 capital expenditures as $14,378,000;
  - Column (c) identifies the 12 months ending April 30, 2026 capital expenditures as $65,931,000;
  - Column (d) identifies the 12 months ending April 30, 2027 projected bridge year capital expenditures as $77,719,000; and
  - Column (e) identifies the 28 months ending April 30, 2027 projected bridge year capital expenditures as $147,360,000.
- For Investments expenditures, "Labor" line items include employee labor; "Software" line items include software licenses and maintenance contracts; "Material" line items include hardware purchases and maintenance contracts; "Contractor" line items include staff augmentation, managed services, and other contracted services; "Non-Labor Overhead" line items include overheads; and "Non-Labor Others" line items include pension expense, administrative/general expense, AFUDC, and business expenses.

Q. Please explain Confidential Exhibit A-20 (SHB-5).

A. Confidential Exhibit A-20 (SHB-5) identifies the electric allocation of projected capital and O&M expenditures to procure, install, and implement the software and infrastructure requested in my testimony to meet business requirements. Both O&M and capital are required to complete the projects included in the test year. This exhibit provides details regarding all projects included in this rate case filing for the IT Department. Specifically, within this exhibit:

- Column (a) provides the year of spending for each line item project;
- Column (b) identifies the project name associated with each line item capital and O&M expenditure for the applicable year or years;
- Column (c) identifies the Federal Energy Regulatory Commission ("FERC") category relative to the line item project's asset type;
- Column (d) identifies the Business Category of the project;
- Column (e) provides a synopsis of the project, including the project description and information on project scope, functionality, and benefits;
- Column (f) identifies the project's start date;
- Column (g) identifies the project's end date;
- Column (h) provides the project's cost/benefit ratio;
- Column (i) provides the total Company expected project capital costs;
- Column (j) provides the total Company expected projected O&M costs;
- Column (k) identifies the project's estimate type;
- Column (l) provides the project's electric portion total capital expenditure for the applicable year or years;
- Columns (m) through (r) provide the details of categorical spend that sum to the total line item Project Capital Spend for the applicable year or years broken down by:
    - Software costs (m);

- Material costs (n);
- Labor costs (o);
- Contractor costs (p);
- Non-Labor Overhead costs (q); and
- Non-Labor Other costs (r).

- Column (s) provides the project's electric portion total O&M spend for the applicable year; and

- Columns (t) through (y) provide the details of categorical spend that sum to the total line item Project O&M Spend for the applicable year or years by the following categories:
  - Software costs (t);
  - Material costs (u);
  - Labor costs (v);
  - Contractor costs (w);
  - Non-Labor Overhead costs (x); and
  - Non-Labor Other costs (y).

Q. Please explain the difference between Exhibit A-12 (SHB-4), Schedule B-5.1, and Confidential Exhibit A-20 (SHB-5).

A. Exhibit A-12 (SHB-4), Schedule B-5.1, and Confidential Exhibit A-20 (SHB-5) are both capital expenditure exhibits that display different views to address the different requirements of the MPSC, as well as the IT Department, as outlined below:

- Exhibit A-12 (SHB-4), Schedule B-5.1, is a high-level summary of capital expenditures by year, by business category or product line, and by categorical spend; and

- Confidential Exhibit A-20 (SHB-5) is a more comprehensive exhibit displaying the detail of each project over the four-year time periods of 2024, 2025, 2026, and 2027.

Q. Please explain Confidential Exhibit A-21 (SHB-6).

A. Confidential Exhibit A-21 (SHB-6) is an Executive Summary report generated from the Company's internal BPS. This exhibit provides the approved business case information for each IT project in Confidential Exhibit A-20 (SHB-5). Confidential Exhibit A-20 (SHB-5) addresses the Commission's interest in:

- projects having approved business cases;
- total project cost for multi-year projects;
- associated hard savings; and
- benefit-cost overall value utilized by the Company.

This exhibit provides the same view the Company uses internally to review the Executive Summary of each business case approved to be included in the test year. It also outlines the total Company cost of ownership of each project, including the initial one-time project investment which could fund work occurring over multiple years, and the projected ongoing support costs after project implementation. Additionally, it identifies recurring hard savings over the life of the investment and provides the cost benefit ratio with a zero breakeven point calculated by the Company's internal BPS. Specifically, within each section of this exhibit:

- Header Information section includes project name, the date the report was generated, and BPS identification number. Specifically:
  - Project Name is the name of the project that indicates the project objective;
  - Report Pulled is the date the Executive Summary report was generated from BPS; and
  - Item ID is the unique identifier from BPS.

- Basic Information section includes work category, work type, alias, brief description, portfolio, organization, business unit, and department. Specifically:
    - Work Category identifies classification of work and activities based on the Company methodology;
    - Work Type identifies "project" as the type of work for all IT investments;
    - Alias identifies historical project names for reference;
    - Description identifies a brief description of the project's intent and the expected outcome;
    - Portfolio identifies the financial planning portfolio for whom the work will be performed;
    - Org identifies the financial planning organization for whom the work will be budgeted;
    - Business Unit identifies the business unit for whom the work will be budgeted; and
    - Dept identifies the department for whom the work will be budgeted.
- Work Objectives includes a synopsis of the project, including the problem statement; objectives; information on project scope, functionality, and benefits; and alternatives considered. Specifically:
    - Problem Statement provides an explanation of the problem(s) the work addresses;
    - Objectives provides information about the business value the project will deliver;
    - Scope describes the high-level business functionality and a list of high-level project deliverables; and
    - Alternatives provide a summary of each of the alternatives considered, why each alternative was not selected and the rationale behind the alternative selected.
- Dates section includes the projected implementation phase start or end dates for projects, with the exception of the Annual Spend Programs such as Asset Refresh Programs, Application Currency, and Enhancements. Specifically:

- Initiation is the start date of the project Plan phase;
- Project Plan & Scope Definition is the end date of the project Plan phase;
- Final Engineering, Planning & Design is the end date of the Design phase;
- Execution is the end date of the Execute phase;
- In-Service/Go-Live is the project's implementation date; and
- Closeout is the end date of the Close phase.

- Funding Summary section includes a Total Company summary and detailed breakdown of projected categorical spend by year for each project. Specifically:
  - Summary of the Total Cost of Ownership of projected capital expenditures and O&M expense for each project, including ongoing maintenance, where:
    - Cap+COR is the total of all the capital expenditures; and
    - O&M is the total of all the O&M expense for the project implementation and ongoing maintenance.
  - Total Project Cost contains a detailed categorical breakdown for projected capital expenditures and O&M expense for each project, excluding ongoing maintenance, where:
    - Labor includes the internal staffing costs for project implementation;
    - Outside Services includes the external labor and services for project implementation;
    - Business Expenses/Overheads includes costs for items such as training, travel, lodging, and meals and Loadings & Allocations for Corporate Overheads and AFUDC;
    - Employee Benefits includes costs for employee benefits;
    - Material includes costs for hardware purchases;
    - Licenses, Permits & Fees includes costs for software and hardware licenses and maintenance; and
    - Other includes miscellaneous costs.

- Value & Impacts Summary Section provides a summary of the projected cost and benefits, risk and other value associated with a project for Capital expenditures and O&M expense, including ongoing maintenance, where:
    - For purposes of O&M:
        - Reduction includes the hard O&M savings;
        - Initial includes the implementation and ongoing maintenance costs;
        - Incremental includes any other O&M costs; and
        - Net is the difference of the reduction, initial, and incremental O&M costs.
    - For purposes of Cap+COR:
        - Reduction includes any hard capital savings;
        - Initial includes the implementation costs;
        - Incremental includes any other capital costs; and
        - Net is the difference of the reduction, initial, and incremental capital costs.
    - For purposes of Revenue:
        - Reduction includes any expenses;
        - Initial includes implementation revenue;
        - Incremental includes any increase in revenue; and
        - Net is the difference of the reduction, initial, and incremental revenue.
    - For purposes of determining financial value of a project, the B/C Ratio (Overall), as shown in the figure below, is the net present value of the change in O&M, plus change in Capital, plus change in Revenue, divided by Total Cost of Ownership set with a breakeven point at zero.

$$\textbf{Financial Value}\ (F_{Overall}) = \frac{\sum B}{\sum C} - 1$$

Where
B = Benefits
C = Total Costs

- For purposes of identifying risk:
  - Type of Corporate Risk;
  - Level of impact;
  - Likelihood of risk; and
  - Description of risk.
- And, for purposes of identifying other value:
  - Type of other value; and
  - Description of other value.

Q. Please explain the breakeven point for the Company's B/C Ratio (Overall).

A. Using the Company's internal BPS B/C Ratio (Overall), the breakeven point is equal to zero where financial benefits and total costs are equal. If the result of the calculation is greater than zero, financial benefits exceed costs. If the result is less than zero, total cost of ownership exceeds the financial benefit.

Q. Does the cost summary component in the Company's B/C Ratio (Overall) use the total one-time project cost, or the total one-time project cost plus the ongoing support costs?

A. The Company's internal BPS B/C Ratio (Overall) cost summary denominator uses total one-time project cost plus the ongoing support costs.

Q. Where is the total Company project cost number distinguished from the total Company project cost number that includes ongoing maintenance cost?

A. The total one-time Company project cost is the Total Project Cost at the bottom right corner of the Funding Summary Section of Confidential Exhibit A-21 (SHB-6). This section of the Funding Summary section, starting with Labor, lists the breakdown of different cost categories for this investment. The total projected Company cost of ownership, including annual ongoing support costs, is the Total Cost of Ownership value on the right of the Funding Summary Section.

INVESTMENT IDENTIFICATION, PRIORITIZATION, APPROVAL, AND PROJECT PLANNING

Q. Please describe how technology projects are initiated, prioritized, and approved within the Company.

A. The initiation of a technology project begins with identification of a need for new or updated technology to meet the requirements of the Company's customers, including technology that customers interact with directly, and technology that sustains and improves reliability in service of customers. For example, IT collaborated closely with Company witnesses and representatives from the electric departments to identify technology projects and foundational digital investments necessary to enable the IRP and EDIIP. The joint teams prepared business cases for each of the projects utilizing standard format and content.

After sponsor approval, individual projects are prioritized based on an evaluation of the benefits, costs, customer value, and necessity to Company goals through a series of reviews by cross-functional business teams. The highest-ranking projects within the level of IT funding approved through the Company's budget and rate case process are selected

for implementation and approved by each business area, followed by approval of the overall IT budget by the senior officer team. Due to the rapid pace of technology change and quickly changing business conditions, emergent projects are identified and vetted through IT and the affected internal business areas throughout the year as business objectives, Company goals, and customer needs and expectations evolve.

Q. Please explain how IT's investment forecasts evolve over the course of project planning and implementation.

A. IT's investment forecasts begin with a ROM estimate. The Company uses the term "ROM" to characterize an initial estimate that includes research, analysis, and a business case. ROM estimates are typically determined by technology and subject matter experts inside and outside the Company in comparison to historical actual costs for similar projects. The purpose of the ROM estimate is to determine whether the estimated costs justify the value provided by the new capabilities without spending an inordinate amount of investment planning O&M developing the bottom-up estimate. From that point, investment forecasting depends on the method used to deliver the intended solution. In the case of Agile delivery, the project team targets the delivery of the highest business value capabilities within the projected funding. In the case of traditional waterfall delivery, once the formal design of a project has concluded, IT subject matter experts perform a detailed definitive estimate for execution. Factors may arise during project execution, such as resource needs, delays in receiving materials, changes in project schedule that shift spending between years, and changes in project scope or complexity that results in funding needs being lower or higher than initially estimated through the ROM process.

Q. Do the Company's total IT capital projections reflect a 20% reduction for those projects whose projections are based on a ROM?

A. Yes. Despite ROM cost-cutting concerns, the total capital projections include a 20% reduction for those projects whose projections are based on a ROM. In order to prevent over recovery, a 20% ROM adjustment is calculated by Business Category for those projects with a ROM estimate with the expectation that the full costs of approved projects may be recovered in a future rate case. These reductions are included in the table below and further reflected in Confidential Exhibit A-20 (SHB-5). Additionally, the ROM Adjusted Test Year Capital is identified for each project later in my testimony.

Year	Projected	Adjusted Projected (20% ROM Adjustment)
2024	$44,022,631	$44,022,631
2025	$56,793,609	$52,118,163
2026	$99,164,570	$84,574,240
2027	$73,477,399	$64,007,880
Test Year	$90,602,180	$77,718,786

Q. Was this 20% reduction to capital expenditures for all ROM estimate projects a reaction to the Commission's decision on page 128 of its December 22, 2021 Order in Case No. U-20963?

A. Yes, in Case No. U-20963, MPSC Staff ("Staff") recommended a 20% disallowance for ROM estimates (Case No. U-20963, 6 TR 4081), and the Commission agreed saying that the ROM estimates are akin to contingency costs. The 20% reduction to capital expenditures for all ROM estimate projects used by IT in this case differentiates the Company's ROM estimates from the ROM estimates it used in Case No. U-20963 (in fact, the 20% reduction reflects Staff's position in Case No. U-20963) and further shows that the ROM estimate projects do not include contingency. Contingency is a project

management best practice to add and reserve a percentage of a project's budget for unforeseen circumstances encountered during the course of the project. Due to previous disallowances, IT estimates do not include contingency. The ROM estimate is (1) intended to cover the full cost of the project rather than a portion, (2) built to address specific scope rather than unforeseen events, and (3) is calculated by technology and subject matter experts for a specific project whereas contingency is a percentage allocation based on an industry percentage value and/or project risk rating.

Q. Which exhibits contain the estimate breakdown for each project?

A. Confidential Exhibit A-20 (SHB-5) contains each project's electric allocation spend for the applicable year or years broken down by software, materials, labor, contractor costs, non-labor overhead, and non-labor other costs. Confidential Exhibit A-21 (SHB-6) contains Company spend for each project in the historical, bridge, and test years, broken down by year, that shows:

- Staffing;
- Outside Services;
- Business Expenses/Other;
- Employee Benefits;
- Materials, Licenses, Permit & Fees; and
- Other.

Q. Do all the projects included in the test year have project plans and schedules?

A. All projects included in the test year will have project plans and target dates at levels commensurate with their current phase. Some projects are continuing from an earlier period into the test year and have more definitive project plans for delivery. When the budget is released to a project to begin the official Plan phase, the product team will

develop a more specific project plan that includes progressively more detail as the project moves through its different phases. In the case of projects executed using Agile methods, a high-level plan will be developed at the start of the project that includes an estimated number of time-bound delivery cycles, or sprints, in which the targeted scope backlog will be delivered.

INVESTMENT PROJECTS

Q. Please provide a description of the various IT investment business categories or product lines to be highlighted in testimony.

A. Costs, descriptions, benefits, alternatives, and other relevant project information for each individual project can be found in Confidential Exhibits A-20 (SHB-5) and A-21 (SHB-6). The IT investment projects are grouped into the following areas for explanation in testimony:

- **Electric and Electric & Gas Shared** projects that enable the IRP and EDIIP for Asset Management; Work Management; System Automation and Control, Security and Privacy; and Advanced Analytics that are necessary components to enable the Company to be an energy partner that customers, regulators, and the people of Michigan can count on to provide a safe, affordable, reliable, clean, and equitable electric system;

- **Customer** projects that are necessary to enable the Company to comply with regulatory billing changes, improve billing functionality, implement capabilities to assist low-income customers with energy assistance, increase the Company's ability to serve customers within the channel of their choice, and engage customers to enroll in demand response and energy waste reduction programs;

- **Corporate** projects that support internal departments of the Company are crucial to running an efficient business such as Treasury; Tax; Legal; HR, also known as People and Culture; Governmental, Regulatory and Public Affairs; Supply Chain and Facilities, also known as Operations Support; Finance; and Risk & Compliance;

- **IT/Digital Foundation** projects create the technology platforms, tools, processes, and frameworks that are required to enable IRP, EDIIP, and

customer service outcomes. This includes ARP, application currency, upgrade and replacements, and digital and foundation capabilities projects; and

- **Security** projects are necessary to deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal effect if or when a threat occurs, comply with all governmental and industry regulations, and enable the Company to secure customer data.

IT Projects Enabling Other Areas

Q. Please explain the Electric and Electric & Gas Shared projects enabling IRP and EDIIP.

A. Below are the projects enabling the IRP and EDIIP. Investments in digital capabilities are essential to achieving the Company's IRP and EDIIP business plans and Work Management improvements. A synopsis of each project with its value is included in the testimony of other Company witnesses, as indicated below.

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M	Witness	Exhibit References
Electric Geographic Information System (GIS) Design Platform Modernization	$1,476,532	$1,181,225	$136,794	M. Kelly	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Catastrophic Crewing (CatCrew) Version 2.0	$351,467	$281,173	$57,067	A.Snider	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Electric GIS Utility Network Transformation	$1,324,225	$1,059,380	$519,952	M. Kelly	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Integrated Energy Management Platform Optimization	$1,343,299	$1,074,639	$507,797	M. Metz	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Service Restoration Artificial Intelligence	$825,723	$94,746	$660,578	A.Snider	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1

Additionally, the Application Currency-Electric-O&M and Capital, Application Currency-Electric & Gas Shared-O&M and Capital, Product Family Enhancements-Electric-O&M

and Capital, and Product Family Enhancements-Electric & Gas Shared-O&M and Capital will be discussed later in my testimony.

Q. Please explain the test year projects included in the Customer area.

A. Below are projects included within the Customer area. These digital investments support lower cost of customer service, increase customer engagement and enrollment in programs, and increase use of digital platforms. A synopsis of each project with its value is included in the direct testimony of Company witness Jessica R. Byrom:

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	O&M	Exhibit References
Customer Order Service Tracker	$735,345	$588,276	$154,745	A-12 (SHB-4), line 2 A-19 (SHB-3), line 1
Multi-Account Online Account Management	$893,008	$714,406	$185,073	A-12 (SHB-4), line 2 A-19 (SHB-3), line 1

Additionally, the Application Currency-Customer-O&M and Capital and Product Family Enhancements-Customer-O&M and Capital will be discussed later in my testimony.

Q. Please explain the projects included in the Corporate area.

A. Below are projects included within the Corporate area. These digital solutions can optimize and even transform these foundational services. A synopsis of each project with its value is included in the direct testimony of Company witness Matthew J. Foster:

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M	Exhibit References
2025 Union Contract Changes	$0	$0	$99,515	A-12 (SHB-4), line 1 A-19 (SHB-3), line 1
Enterprise Risk Management	$0	$0	$47,135	A-12 (SHB-4), line 1 A-19 (SHB-3), line 1
Self Service Vendor Portal	$61,629	$49,303	$77,930	A-12 (SHB-4), line 1 A-19 (SHB-3), line 1

Additionally, the Application Currency-Corporate-O&M and Capital and Product Family Enhancements-Corporate-O&M and Capital will be discussed later in my testimony.

IT/Digital Foundations and Capabilities

ARP

Q. Please explain the value of projects included in ARP, and how the Company determines the hardware refresh frequency.

A. The Company's ARP projects replace technology assets in line with industry and Company life-cycle expectations for the specific assets in each type of program. Replaced assets are recycled, donated, or sold if there is residual value. The Company's research shows that industry standards on refreshing hardware are generally three to five years, although the Company refreshes monitors every eight years based on Company data related to historical failure rates. Refreshing hardware at the recommended cycle allows the Company to: (1) reduce security risks and help ensure devices are updated and patched to avoid vulnerabilities; (2) avoid costs due to increasing hardware failures; (3) avoid frustration for its customers and lost productivity for its employees due to downtime; (4) receive continued operating system support as older versions are retired by the manufacturer; and (5) ensure employees have the required hardware to support their work.

Below is a link to information on industry standards the Company has reviewed in determining its hardware refresh time periods:

- Michigan.gov, Information Technology Equipment Life Cycle[4]

[4] https://www.michigan.gov/dtmb/-/media/Project/Websites/dtmb/Law-and-Policies/Legislative-Reports/FY2023/Sec-829-Report-of-PA-166---IT-Lifecycle-2023.pdf?rev=7b90fd55a9104194aa50e978d570bfec&hash=1A969DADCAF5A71CD5F0746D0DEE08A4

Q. Please describe Exhibit A-22 (SHB-7).

A. Exhibit A-22 (SHB-7) shows the detailed projected and actual capital expenditures of each ARP. Specifically:

- Column (a) provides the unit description;
- Column (b) provides the average unit cost;
- Column (c) provides the total number of units for the specified year;
- Column (d) provides the total number of units for the specified year;
- Columns (e) through (f) provide total actual or projected capital expenditures for the specified year;
- Column (g) provides the total projected capital expenditures for the test year or the total actual electric allocation of capital expenditures for the specified year; and
- Column (h) provides electric allocation of capital expenditures for the specified year.

Q. Please explain the ARP and infrastructure projects, as reflected in Exhibit A-22 (SHB-7).

A. Each page of Exhibit A-22 (SHB-7) relates to a different ARP and infrastructure project, which I discuss further below.

Q. Please explain the ARP-Collaboration project.

A. The ARP-Collaboration project has the following synopsis:

- The **ARP-Collaboration** project requires $1,153,267 in capital and $140,683 in O&M in the test year.
  - **Description:** This project will replace the Company's obsolete or out-of date audio, visual, telephony, and other communication collaborative tools and equipment.
  - **Problem Statement:** When collaboration assets used to support customer interactions and business operations are obsolete or out-of-date, they are more difficult to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle.

- **Objectives:** This project creates value by: (1) ensuring the stability and reliability of the Company's audio, visual, telephony, and other communications systems; and (2) migrating to new collaboration assets.

- **Scope:** The project scope consists of: (1) replacing aging collaboration assets; and (2) installing new collaboration assets to meet evolving business requirements.

- **Alternatives:** The alternatives considered included: (1) continuing to operate collaboration assets beyond a five-year refresh cycle, or (2) refreshing collaboration assets based on a five-year refresh cycle while evaluating the health of the asset and evolving business requirements. The alternative to operate the collaboration assets beyond a five-year refresh cycle was not selected due to the risk that asset failures would cause stability and reliability issues for employees supporting the Company's customers, as vendors do not provide extended support after five years. The Company chose to refresh the collaboration assets based on a five-year refresh cycle and evaluate the health of the asset and evolving business requirements to reduce the risk of impacting the productivity of employees supporting customers.

Q. Do the Company's 2026 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project differ from the $576,228 projected in Case No. U-21585?

A. Yes. The 2026 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project of $1,022,838 (Confidential Exhibit A-20 (SHB-5), column (n), line 217) are $446,610 more than the $576,228 projected in Case No. U-21585 (Exhibit A-88 (SK 6), column (m), line 309).

The difference is due to the call recording system's hardware being end of life and there is risk of failure. Secondly, there is a need to refresh an additional auditorium to improve collaboration capabilities.

Q. Please explain the change made with the ARP-Cyber Security project.

A. Beginning in 2025, the ARP-Cyber Security project is being replaced with ARP-Cyber Security-Common, ARP-Cyber Security-Electric, and ARP-Cyber Security-Gas projects

to improve the tracking of these assets and better align the projects with the resources performing the work.

- The **ARP-Cyber-Common** project requires $843,849 in capital and $11,215 in O&M in the test year.
  - **Description:** This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions.
  - **Problem Statement:** When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.
  - **Objectives:** This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.
  - **Scope:** The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three- to five-year hardware lifecycle; and (2) performing application upgrades.
  - **Alternatives** The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresch cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warrant repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.
- The **ARP-Cyber-Electric** project requires $430,291 in capital and $17,616 in O&M in the test year.
  - **Description:** This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions.
  - **Problem Statement:** When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.

- **Objectives:** This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.

- **Scope:** The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three- to five-year hardware lifecycle; and (2) performing application upgrades.

- **Alternatives:** The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresch cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warrant repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs..

Q. Please explain the changes made with the ARP-Core Network, ARP-Local Area Network, and ARP-Infoblox projects.

A. Beginning in 2025, the ARP-Core Network, ARP-Local Area Network, and ARP-Infoblox projects have been replaced with ARP-Network-Common, ARP-Network-Electric, and ARP-Network-Gas projects due to the move of network resources to Security. In addition, a portion of the units from the ARP-OT Electric have been moved to these new projects. These changes were made to improve tracking of these assets and better align the projects with the resources performing the work.

- The **ARP-Network-Common** project requires $549,198 in capital and $11,177 in O&M in the test year.

  - **Description:** This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks shared by Electric and Gas.

  - **Problem Statement:** When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to

support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle.

- **Objectives:** This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks.

- **Scope:** The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices.

- **Alternatives:** The alternatives considered include: (1) continuing to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; or (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.

- The **ARP-Network-Electric** project requires $51,630 in capital and $916 in O&M in the test year.

  - **Description:** This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks for Electric.

  - **Problem Statement:** When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle.

  - **Objectives:** This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks.

- **Scope:** The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices.

- **Alternatives:** The alternatives considered include: (1) continuing to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; or (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.

- The **ARP-OT Support Electric** project requires $1,084,783 in capital and $20,142 in O&M in the test year.

  - **Description:** The ARP-OT Support Electric project will replace dated and obsolete servers on a rotating five-year refresh schedule.

  - **Problem Statement:** When OT Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle.

  - **Objectives:** This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure.

  - **Scope:** The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements.

  - **Alternatives:** The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle; or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Electric SCADA.

- The **ARP-OT Support Common** project requires $42,643 in capital and $1,062 in O&M in the test year.

  - **Description:** The ARP- OT Support Common project will replace dated and obsolete servers shared by Electric and Gas on a rotating five-year refresh schedule.

  - **Problem Statement:** When OT Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle.

  - **Objectives:** This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure.

  - **Scope:** The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements.

  - **Alternatives:** The alternatives considered included: (1) continue to operate hardware beyond a five year refresh cycle; or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure.

- The **ARP-Physical Security** project requires $1,449,104 in capital and $7,826 in O&M in the test year.

  - **Description:** The ARP-Physical Security, formerly known as Physical Security Asset Refresh, will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns.

  - **Problem Statement:** The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current considerations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster responses to emergencies and

incidents. If the Company does not maintain these assets, it could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage.

- **Objectives:** The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reducing gaps in functionality; and (3) optimize overall system performance.

- **Scope:** Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems.

- **Alternatives:** Alternatives considered include: (1) not refreshing physical security assets; and (2) defer a portion of the refresh of physical security assets per an asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security concerns, incident resolution, and the inability to meet FERC requirements. The alternative selected maintains compliance, reduces redundancies and gaps in functionality, and optimizes overall performance of physical security systems.

Q. Please explain the ARP-PAM project.

A. The ARP-PAM project has the following synopsis:

- The **PAM** project requires $237,618 in capital and $3,099 in O&M in the test year.

  - **Description:** This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one.

  - **Problem Statement:** When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

  - **Objectives:** This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications.

- **Scope:** The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. This does not mean that all printers are replaced after five years – merely that printers are assessed on a five-year cycle for possible replacement.

- **Alternatives:** The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years would require the printers to be assessed monthly to ensure they are not run to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.

Q. Do the Company's 2025 projected electric allocation capital expenditures for material costs for the ARP-PAM project differ from the $501,862 projected in Case No. U-21585?

A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project of $1,013,149 (Confidential Exhibit A-20 (SHB-5), column (n), line 147) are $511,287 more than the $501,862 projected in Case No. U-21585 (Exhibit A-88 (SK 6), column (m), line 253).

Q. Please explain why the Company's 2025 projected electric allocation capital expenditures for material costs for ARP-PAM differ from the previous case.

A. The Company's 2025 projected electric allocation capital expenditures for material costs of $1,013,149 differ for ARP-PAM from the materials projections in the previous case due to the deferral of refreshes of devices from 2020 – 2023. The refreshes were deferred due to resources working remotely due to the pandemic.

Q. Please explain the ARP-FDAM project.

A. The ARP-FDAM project has the following synopsis:

- The **ARP-FDAM** project requires $4,850,461 in capital and $3,099 in O&M in the test year.
    - **Description:** This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility.
    - **Problem Statement:** When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle.
    - **Objectives:** This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices before they fail; and (2) allowing field workers to complete their job tasks.
    - **Scope:** The project scope consists of replacing field device assets according to the four-year refresh cycle.
    - **Alternatives:** Alternatives considered include: (1) using outdated equipment. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact meter readers' ability to complete job tasks. It would also complicate the Company's efforts to meet the MPSC's meter reading factor and consecutive estimated targets, and it could cause applications to run poorly or stop functioning; (2) The second alternative considered was to replace the hardware. The Company selected this option to alleviate the above concerns.

Q. How are the annual projected costs created for the ARP-FDAM project?

A. The ARP-FDAM project has two categories, which are replacements and new purchases. Each of these categories include field devices. A further description of replacements and new purchases is as follows:

- **Replacements:**
    - Are determined by pulling the quantity of device types with a scheduled retirement year:
        - Field devices scheduled retirement year is four years from purchase;
    - The model of device determines the unit cost. The total of these devices with their current unit cost is established for a particular year's budget;

- Accessories for field devices are projected based on the number of planned replacements and include desk docks, vehicle docks, and ac adapters; and
- Carryover devices are added from the previous year to address aging devices first.

- **New Purchases:**
  - Are projected at $1 million annually.
    - The Company reviews actual historical new purchase costs for the past four years to ensure the $1 million is reasonable and prudent;
  - The costs cover the field devices required for the employee/contractor and associated accessories.

The four-year cycle for field devices, along with the projected new purchases, are listed in the associated Exhibit A-22 (SHB-7).

Q. Please describe variances from year to year for the ARP-FDAM project.

A. Variances for the ARP-FDAM project are a result of changes to new purchases, scheduled replacements, and incremental unit costs. Starting in 2024, there has been a one-time change for new field device purchases. These devices are now a part of the ARP-FDAM project, rather than the ARP-WAM project. Moreover, there is a change in the replacement of some field devices, which were initially planned under the ARP-WAM project. These devices were included in ARP-FDAM starting in the year 2024 going forward. Exhibit A-22 (SHB-7), page 5, details the devices, number of units, and unit costs for each type of device. Below are summary charts with the variance reasons for each year separated between replacement and new purchase categories.

Replacements

Year	Field Device	Reason for variance
2024 Actual	662	• Field device replacements based on refresh schedule. • 84 field device replacements moved from ARP-WAM to ARP-FDAM.
2025 Plan	480	• Field device replacements based on refresh schedules. • 415 fewer refreshes than planned due to retirement of all G1 version devices, downsizing Marshall training room needs and reduced gas construction needs.

2026 Plan	1,338	• Field device replacements based on refresh schedule. • 215 field device replacements moved from ARP-WAM to ARP-FDAM. • 425 field device replacements that were purchased as a part of other efforts in 2022.
2027 Plan	972	Field device replacements based on refresh schedule.

New Purchases

Year	Field Device	Reason for variance
2024 Actual	149	Field devices based on actual new employee/contractors.

Q. Do the Company's 2025 projected electric allocation capital expenditures for material costs for the ARP-FDAM project differ from the $3,387,972 projected in Case No. U-21585?

A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the ARP-FDAM project of $2,172,954 (Confidential Exhibit A-20 (SHB-5), line 144, column (n)) is $1,215,019 less than the $3,387,972 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 252).

The following describes the reason for the difference:

1. Field device replacements decreased $1.20 million due to fewer refreshes than planned based on retirement of all G1 version devices, downsizing Marshall training room needs, and reduced gas construction needs; and

2. New purchases electric allocation decreased by $0.01 million based on current electric allocation factors that are updated annually.

Q. Do the Company's 2026 projected electric allocation capital expenditures for material costs for the ARP-FDAM project differ from the $2,948,011 projected in Case No. U-21585?

A. Yes. The 2026 projected electric allocation capital expenditures for material costs for the ARP-FDAM project of $5,136,183 (Confidential Exhibit A-20 (SHB-5), line 218,

column (n)) is $2,188,172 more than the $2,948,011 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 310).

The following describes the reason for the difference:

1. Field device replacements increased by $0.72 million due to 215 field devices moved from ARP-WAM to ARP-FDAM;

2. Field device replacements increased by $0.29 million due to 88 field devices that were initially purchased for training in 2022;

3. Field device replacements increased by $1.13 million due to 337 field devices that were initially purchased as a part of an Electric and Gas Operations effort in 2022;

4. Field device replacements increased by $0.02 million due to an increase in unit cost for CF55 field devices; and

5. Labor and Non-Labor Other increased by $0.03 million to support the increase in number of field device replacements.

Q. Please explain the ARP-Radio project.

A. The ARP-Radio project has the following synopsis:

- The **ARP-Radio** project requires $1,029,710 in capital and $133,351 in O&M in the test year.
    - **Description:** This project will refresh hardware to include: 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices, vehicle consoles in service trucks, other communications equipment, and associated test equipment. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 10-year lifecycle basis. Cellular modems are refreshed on a five-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle.
    - **Problem Statement:** 800MHz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customers service and critical infrastructure. Company radio and cellular systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing or becoming obsolete. The refresh of this equipment in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and

concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety.

- **Objectives:** This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure.

- **Scope:** The project scope consists of: (1) scheduled replacement of radios, modems, and consoles; and (2) installing additional radios, modems, and console assets to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters.

- **Alternatives:** The alternatives considered include: (1) Replacing the existing units with new units from other radio and modem manufacturers; (2) Purchasing new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.

Q. Please explain the ARP-Server and Storage project.

A. The ARP-Server and Storage project has the following synopsis:

- The **ARP-Server and Storage** project requires $323,576 in capital and $24,131 in O&M in the test year.

  - **Description:** This project will replace or augment server and storage infrastructure for the Company.

  - **Problem Statement:** When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be more challenging to keep current with Security updates. The Company also runs the risk of failure of these assets impacting customer interactions and business operations if it does not adhere to a regular five- to seven-year refresh cycle.

  - **Objectives:** This project creates value for the Company through: (1) improved stability and availability of business-critical applications by

proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use.

- **Scope:** The scope of this program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements.

- **Alternatives:** The alternatives considered were to purchase extended maintenance, move some of these assets to the cloud with the Digital - Hybrid Cloud and Data Center Migration project, or to replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option.

Q. Please explain the ARP-WAM project.

A. The ARP-WAM project has the following synopsis:

- The **ARP-WAM** project requires $4,395,889 in capital and $39,776 in O&M in the test year.

  - **Description:** This project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates.

  - **Problem Statement:** When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

  - **Objectives:** This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks.

  - **Scope:** The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources.

  - **Alternatives:** The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the

replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP in future years based on the number of devices that were not replaced during the four-year refresh cycle ; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets; and an eight-year cycle for monitors to alleviate these concerns.

Q. Would increasing the replacement cycle for the ARP-WAM refresh cycle from four years to five- to seven-years have a negative impact on the Company and its customers?

A. Yes. Increasing the replacement cycle for Personal Computer ("PC") Devices from four years to five to seven years would have a negative impact on the Company and its customers. This is demonstrated through industry data, internal incident data, PC warranty duration, and lost productivity.

- These references reinforce replacing PCs at four years or less:
  - Michigan.gov, Information Technology Equipment Life Cycle. https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_FY_2021_717757_7.pdf
  - https://i.crn.com/sites/default/files/ckfinderimages/userfiles/images/crn/custom/INTELBCCSITENEW/WhitePaper_EnterpriseRefresh.pdf
- The vendor's three-year warranty duration for Company PCs combined with the incident history reinforce four years is the optimum time for replacement.

The labor cost of addressing incidents and lost productivity, the warranty period, and external references confirm PC and field device replacement on a four-year cycle. Similarly, Company historical failure rates for monitors indicate an eight-year cycle as ideal, which is what the Company employs for monitors.

Q. How are the annual projected costs created for the ARP-WAM project?

A. The ARP-WAM project has two categories, which are replacements and new purchases. Each of these categories include PC devices and monitors. A further description of replacements and new purchases is as follows:

- **Replacements:**
  - Are determined by pulling the quantity of device types with a scheduled retirement year:
    - PC devices scheduled retirement year is four years from purchase, and
    - Monitors scheduled retirement year is eight years from purchase.
  - The model of device determines the unit cost. The total of these devices with their current unit cost is established for a particular year's budget;
  - Accessories for PC devices are projected based on the number of planned replacements and include keyboards, surge protectors, docks, backpacks, and cables; and
  - Carryover devices are added from the previous year to address aging devices first.
- **New Purchases:**
  - Are projected at $1 million annually.
    - The Company reviews actual historical new purchase costs for the past four years to ensure the $1 million is reasonable and prudent;
  - The costs cover the PC devices required for the employee/contractor and associated accessories.

The four-year cycle for PC devices and the eight-year cycle for monitors, along with the projected new purchases, are listed in the associated Exhibit A-22 (SHB-7).

Q. Please describe variances from year to year for the ARP-WAM project.

A. Variances for the ARP-WAM project are a result of changes to new purchases, scheduled replacements per four-year PC device and eight-year monitor refresh cycles, previous year deferrals for equipment replacements primarily due to disallowances, and incremental unit costs. Starting in 2025, there has been a one-time change for new field device purchases.

These devices will now be a part of the ARP-FDAM project, rather than the ARP-WAM project. Moreover, there is a change in the replacement of some field devices, which were initially planned under the ARP-WAM project. Exhibit A-22 (SHB-7), page 15, details the devices, number of units, and unit costs for each type of device. Below are summary charts with the variance reasons for each year separated between replacement and new purchase categories.

Replacements

Year	PC Device	Monitor	Reason for variance
2024 Actual	1,839	0	• 138 fewer PC devices replaced due to reduction in resources and reduction of shared PC devices, such as kiosks and lab devices. • 233 Desktop replacements deferred to 2025 due to resource availability. • No monitor replacements planned since monitors' eight-year replacement cycle was completed from 2018-2021. The next monitor replacement is targeted to resume in 2027.
2025 Plan	2,968	0	• 233 Desktop replacements deferred from 2024 due to resource availability. • 218 PC devices that are not planned to be replaced due to reduction in resources. • No monitor replacements planned since monitors' eight-year replacement cycle was completed from 2018-2021. The next monitor replacement is targeted to resume in 2027.
2026 Plan	2,196	0	• No monitor replacements planned since monitors' eight-year replacement cycle was completed from 2018-2021. The next monitor replacement is targeted to resume in 2027.
2027 Plan	2,159	4,318	• Monitor replacements based on an eight-year replacement cycle.

New Purchases

Year	PC Device	Monitor	Reason for variance
2024 Actual	323	331	Based on actual new employee/contractor volume.

Q. Do the Company's 2024 actual electric allocation capital expenditures for material costs for the ARP-WAM project differ from the $4,260,099 projected in Case No. U-21585?

A. Yes. The 2024 actual electric allocation capital expenditures for material costs for the ARP-WAM project of $3,993,657 (Confidential Exhibit A-20 (SHB-5), column (n), line 56) are $266,442 less than the $4,260,099 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 177).

The following describes the difference:

1. Desktop replacements decreased by $0.81 million due to fewer requests for desktops, reduction in resources and shared devices, and deferral of desktop replacements to 2025, as discussed above;

2. Laptop replacements increased by $0.64 million due to more requests for these devices;

3. Accessories decreased by $0.07 million; and

4. New PC purchases decreased by $0.03 million based on actual hiring.

Q. Do the Company's 2025 projected electric allocation capital expenditures for material costs for the ARP-WAM project differ from the $5,896,927 projected in Case No. U-21585?

A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the ARP-WAM project of $5,646,692 (Confidential Exhibit A-20 (SHB-5), column (n), line 148) are $250,235 less than the $5,896,927 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 255).

The following describes the difference:

1. Desktop replacements increased $0.39 million due to deferral of replacements from 2024 to 2025, as discussed above;

2. Laptop and tablet replacements decreased by $0.40 million based on reductions in resources;

3. Accessories decreased by $0.38 million due to decrease in laptop and tablet replacements, as described above; and

4. New purchases electric allocation decreased by $0.01 million based on current electric allocation factors that are updated annually.

Q. Do the Company's 2026 projected electric allocation capital expenditures for material costs for the ARP-WAM project differ from the $4,609,542 projected in Case No. U-21585?

A. Yes. The 2026 projected electric allocation capital expenditures for material costs for the ARP-WAM project of $4,013,510 (Confidential Exhibit A-20 (SHB-5), column (n), line 221) are $596,032 less than the $4,609,542 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 313).

The following describes the difference:

1. Laptop and tablet replacements increased by $0.25 million based planned replacements;

2. Monitors decreased by $0.86 million, as they were inadvertently planned for 2026 and should not have been planned until 2027, per eight-year refresh cycle for monitors.;

3. Accessories decreased by $0.02 million due to decrease in monitors, as described above; and

4. New purchases electric allocation decreased by $0.01 million based on current electric allocation factors that are updated annually.

Upgrades, Replacements, and Application Currency Projects

Q. What are Upgrades, Replacements, and Application Currency projects?

A. Upgrades, Replacements, and Application Currency projects are projects that address the need to upgrade or replace software applications and underlying platforms to a more current version to maintain prudent levels of security, reliability, and interoperability with

associated systems. The Company performs security risk and various types of technical analysis to determine which applications need upgrading or replacing and when. Upgrade and replacement projects are created for larger and more complex application and platform upgrades or replacements that require increased oversight and project management. Smaller upgrades are aggregated by IT product line and spend type in the Application Currency projects.

Q. Please explain the Upgrades and Replacements projects.

A. The following is an explanation of the Upgrades and Replacements projects:

- The **Asset Accounting Tax Upgrade** project requires $65,865 in O&M in the test year.
  - **Description:** The project will upgrade the Company's current accounting asset management tax software to the SaaS version as required by the vendor ensuring continued support of a critical financial application and providing new functionality.
  - **Problem Statement:** In 2025, standard vendor support ends for the current on-premise PowerTax software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility.
  - **Objectives:** This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) moving to a SaaS solution in order stay supported; and (2) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.
  - **Scope:** The project scope includes: (1) evaluating current vendor/product solutions with market leaders; and (2) upgrading the vendor software from the current version to the newer SaaS version or replacing it.
  - **Alternatives:** Alternatives considered include: (1) evaluating other software options. This option would introduce new ongoing support costs

and integrations and may not provide regulatory reporting and other needed improvements. (2) do nothing and remain on unsupported, on-prem tax solution. This option would introduce costly technical and financial risks. (3) upgrading to the newest SaaS version of current on-prem solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **Asset Accounting Upgrade 2025-2026** project requires $27,444 in O&M in the test year.

  - **Description:** The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application.

  - **Problem Statement:** Standard vendor support will be ending for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complex testing activities and too many version increases at any one time.

  - **Objectives:** This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted.

  - **Scope:** The project scope includes: (1) evaluating current vendor/product solutions with market leaders; and (2) upgrading the vendor software from the current version to the newer version.

  - **Alternatives:** Alternatives considered include: (1) evaluateing SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) evaluating other software options. This option would

introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements.(3) upgrading to the newest version of the current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **Asset Accounting Upgrade 2027-2028** project requires $115,263 in O&M in the test year.
  - **Description:** The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application.
  - **Problem Statement:** Standard vendor support will be ending for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complex testing activities and too many version increases at any one time.
  - **Objectives:** This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted.
  - **Scope:** The project scope includes: (1) evaluating current vendor/product solutions with market leaders; and (2) upgrading the vendor software from the current version to a newer version.
  - **Alternatives:** Alternatives considered include: (1) evaluating SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) evaluating other software options. This option would introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) moving to cloud option. This option would be expensive and has an unclear timeline.

(4) waiting until a future upgrade cycle. This option introduces technical risk. (5) upgrading to a newer version of the current solution. This is the preferred option as it will provide more frequent software upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **AxWay Secure Transport 2027 Upgrade** project requires $76,842 in O&M in the test year.

  - **Description:** Axway SecureTransport is the official Consumers Energy multi-protocol Managed File Transfer ("MFT") gateway for securing, managing, and tracking data file flow for business partners and external vendors. Files impacting billing, HR, Supply Chain, Finance, Alternate Energy Programs, Front Office, Back Office, Device Management, Outage Management, and Business Reporting functions utilize these services. This project will update the platform to the current software version, enabling cost saving operational enhancements while retaining data security and platform supportability.

  - **Problem Statement:** As Axway SecureTransport is the public-facing MTF gateway, maintaining platform version integrity is critical to ensuring it remains secure and supportable in the event of a cyber attack, outage or other critical incident. A prolonged outage or incident, for any reason, compromises the ability of the Company to perform mission-critical business transactions in finance, operations, and direct customer support. Upgrading this application also gives the Company the opportunity to properly scale SecureTransport and take advantage of the growing demand for additional, cost-savings features of the tool, such as managing internal Electronic Data Interchange transactions.

  - **Objectives:** The value this project brings the Company, its customers and business partners by: (1) addressing known problems and limitations of the current software platforms; (2) ensuring continued secure, scalable, and critical data transmission services running through Axway; (3) creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste; And (4) merging/streamlining the Company data file transfer services reduces cyber attack vectors and creates a better, more easily maintained and monitored security model.

  - **Scope:** The scope of this project includes (1) upgrading the application and database to the current released and supported versions; And (2) enabling and testing in scope file transfer processes.

  - **Alternatives:** Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because the Axway SecureTransport platform handles critical Company financial, HR, and operational

transactions--the risk associated with problems stemming from an outdated and unsupported version is too high. (2) replacing the platform. The estimated project costs and timetable for replacing the business functions currently performed by the existing Axway SecureTransport platform would be extensive, and operationally, it is not well suited for a SaaS or hybrid cloud solution. In addition to significant platform, application, implementation, and functional testing costs, replacing it would require extensive coordination and testing with all of the internal and external account holders, taking upwards of one calendar year. (3) upgrading the platform. This provides the Company the best, most cost-effective alternative, balancing costs, known risks, and even growing business capacity and productivity.

- The **Critical Substation Upgrade** project requires $3,498,167 in capital ($3,135,966 ROM Adjusted Capital) and $396,667 in O&M in the test year.

  - **Description:** This project will implement enhanced security measures at the Company's most critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time. With the enhanced security posture, Consumers Energy will be better positioned to mitigate malicious activity and increase the reliability of electric delivery to customers.

  - **Problem Statement:** Today, Consumers Energy currently deems 16 substations as business critical to its electric system while an additional 34 substations fall under NERC-CIP compliance. Recent attacks to critical infrastructure have increased the likelihood of an adversary exploiting vulnerabilities at critical substations, increasing the risk for large scale outages and customer impact. The Company's current security measures do not allow it to detect, deter, or monitor potential threats on site. Without the ability to monitor these assets in real-time, the Company is vulnerable to an adversary causing destruction without knowledge of when or how the event took place. A phased implementation would allow the Company to systematically mitigate risk to assets deemed most vulnerable.

  - **Objectives:** The objective of this project is to implement enhanced security measures to better detect, deter, and respond to threats to the Company's electric substations in real-time. This enhanced security posture will align with other utilities that own and operate substations and mitigate disruption to electric service while improving reliability.

  - **Scope:** Enhanced Security measures that will need to be implemented include but are not limited to: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fence intrusion (which will be accomplished through camera systems); (6) subcontractor work of trenching poles, installing equipment, etc.; (7) additional facility lighting; and (8) security equipment maintenance. These activities will be performed

at the following company locations: Acme (Acme), Algoma (Sparta), Alma (Alma), Amber (Ludington), Barry (Hastings), Beals Road (Wyoming), Beecher (Adrian), Beveridge (Flint), Blackstone (Jackson), Boardman (Traverse City), Brickyard (Holton), Broadmoor (Grand Rapids), Campbell (West Olive), Cannon (Rockford), Cement City (Cement City), Churchill (Leslie), Clearwater (Kalkaska), Cleveland (Spring Lake), Cole Creek (Flushing), Crescent (Hillsdale), Croton Dam (Newaygo), David (Pewamo), Deja (Edmore), Dort (Mt. Morris), Dowling (Hudson), Edenville Dam (Hope), Edwards (Kalamazoo), Ellsworth (Grand Rapids), Elm Street (Battle Creek), Eureka (Greenville), Farr Road (Onekama), Gleaner (Freeland), Gratiot Farms (Middleton), Grodi Road (Erie), Grout (Gladwin), Hazelwood (Plainwell), Hemphill (Flint), Hile Road (Muskegon), Hodenpyl Dam (Wexford), Holland Road (Saginaw), HSC Hemlock Semiconductor (Hemlock), Hughes Road (Marshall), Island Road (Charlotte), Jackson Plymouth (Jackson), Lafayette (Battle Creek), Layton (Chesaning), Lindbergh (Kalamazoo), Looking Glass (Lansing), Manlius (New Richmond), McNally (Charlevoix), Miles Road (East Jordan), Monitor (Bay City), Moore Road (Hillsdale), Morrow (Comstock), Muskegon Heights (Muskegon), Oceana (Hart), Ogemaw (West Branch), Page Avenue (Jackson), Pasadena (Flint), Pingree (Allendale), Raisin (Tecumseh), Rice Creek (Albion), Riverview (Kalamazoo), Silicon Hemlock Semiconductor (Hemlock), Simpson (Mendon), Sonoma (Battle Creek), Spartan (East Lansing), Thompson Road (Clarksville), Trowbridge (Allegan), Twining (Twining), Vernon (Clare), VeVay (Mason), Vrooman (Jackson), Washtenaw (Chelsea), Wealthy (Grand Rapids), and Willard (Birch Run).

- **Alternatives:** Alternatives considered include: (1) maintaining the current security perimeter fencing and conducting routine inspections of the sites. This alternative was not selected, as it does not provide the ability to prevent, detect, or respond to threats in real-time. (2) The best option is implementing enhanced security measures at the most critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time.

- The **HR Support Pack and Business Software Inc ("BSI") Upgrade 2026 and 2027** projects require the following O&M in the test year.

Project Year	Test Year O&M
2026	$246,223
2027	$123,112

- **Description:** The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.

- **Problem Statement:** SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.

- **Objectives:** This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.

- **Scope:** The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.

- **Alternatives:** Alternatives considered include: (1) not upgrading to the current support packs, which results in noncompliance with financial rules and regulations and inaccurate payroll.(2) there is no economical cloud solution, so this option was not entertained(3) the Company decided the best alternative is to apply the appropriate support pack upgrades. This option is preferred because it enables the Company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.

- The High Voltage Distribution **("HVD") SCADA Upgrade** project requires $335,461 in capital ($268,369 ROM Adjusted Capital) and $163,773 in O&M in the test year.

  - **Description:** The Electric HVD Monitoring System Upgrade project upgrades the software and hardware components of the HVD SCADA system. This system is used to monitor and control generation, transmission, and HVD voltage circuits. The upgrade will provide new functionality and enable new capabilities.

  - **Problem Statement:** Running on an older version of the HVD Software could have potential impacts on the reliability and resiliency of the low voltage distribution ("LVD") system as well as the HVD system, as distribution reliability metrics depend upon HVD system availability. Maintaining an older version of the software and hardware creates risks associated with vendor responsiveness in addressing problems, as they arise. It will also take more effort to support any upgrades in the future because of difficulties resulting from longer durations between upgrade efforts. If upgrades are delayed, additional full-time resources will be required for the year upgrades occur to address upgrade complexities.

  - **Objectives:** Upgrading the HVD SCADA software and hardware adds value to the Company by ensuring that problems are promptly addressed when they occur. Additionally, the upgrade includes enhancements and fixes to the core product that support the resiliency of electric delivery, ensuring that customers are receiving the energy they need when they need it. Also, the distribution system depends on availability of the HVD system

as staying current with the solution provider upgrades is critical to the resiliency of both systems.

- **Scope:** The scope of this project is an upgrade to the HVD SCADA software and hardware, which encompasses the following: (1) upgrading the application software; (2) upgrading the underlying application hardware; (3) implementing new functionality for improved value to the Company; (4) making necessary configuration changes; and (5) updating documentation related to the integration changes.

- **Alternatives:** Alternative considered include: (1) deferring the biennial upgrade of the SCADA application and its hardware. The Company targets SCADA biennial application upgrades to stay within two versions of the current application state to maintain application stability and cyber security, given the critical nature of the SCADA system. This alternative was not chosen due to increased security risk and the need for vendor support of the application. Additionally, the hardware is already past the end of its useful life and has been moved over to a third-party warranty provider. (2) alternative vendor solution. This option was not chosen because the move from our current vendor would be time consuming and costly. It could also introduce instability as any alternative solutions have not been proven operationally; 3) doing nothing. This option was not chosen due to the critical nature of these systems and the potential operational risks associated with operating on an unsupported solution. (4) The option chosen is to complete the upgrade with associated hardware and software necessary to complete the project that will deliver new functionality for improved value.

- The **Itron Enterprise Edition ("IEE") 2025 Upgrade** project requires $50,812 in O&M in the test year.

  - **Description:** This project will upgrade IEE, which collects the reads from meters to ensure non-estimated bill accuracy.

  - **Problem Statement:** IEE is the Company's keystone application of the Advanced Metering Infrastructure ("AMI"), that provides billing data that includes time of use data. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. IEE is a key component in keeping the Company current, with billing capacity, stability, and accuracy obligations.

  - **Objectives:** This project creates value for the Company by: (1) ensuring the features and functionality needed to meet and exceed customer satisfaction and billing accuracy are available to business partners and IT; and (2) meeting Information Security's requirement to keep applications patched and protected from cyber attack.

- **Scope:** The scope of this project includes: (1) upgrading the IEE applications to the next appropriate versions; and (2) migrating the database to the next version required by the application.

- **Alternatives:** Alternatives considered include: (1) defering the upgrade. This alternative was not selected because it would decouple Itron IEE (Consumers Energy's Meter Data Management ("MDM")) from the Itron security infrastructure introducing application instability, security, and dependency risks to the utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Itron applications, creating more expense to support and no ability to leverage updated tool capability. (2) replacing the platform. Replacing IEE/MDM would require the application business owners to undertake a new initiative mirroring the expense and effort that went into the initial multi-million dollar project.(3) performing the upgrade is the best alternative. This option is superior for both customers and the Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.

- The **Itron Enterprise Edition 2027 Upgrade** project requires $83,541 in capital ($66,833 ROM Adjusted Capital) and $102,784 in O&M in the test year.

  - **Description:** This project will upgrade IEE, which collects the reads from meters to ensure non-estimated bill accuracy.

  - **Problem Statement:** IEE is the Company's keystone application of AMI, that provides billing data that includes time of use data. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. IEE is a key component in keeping the Company current, with billing capacity, stability, and accuracy obligations.

  - **Objectives:** This project creates value for the Company by: (1) ensuring the features and functionality needed to meet and exceed customer satisfaction and billing accuracy are available to business partners and IT; (2) meeting Information Security's requirement to keep applications patched and protected from cyber attack.

  - **Scope:** The scope of this project includes: (1) upgrading the IEE applications to the next appropriate versions; (2) migrating the database to the next version required by the application; and (3) replacing hardware required by the next version to maintain operating system currency.

  - **Alternatives:** Alternatives considered include: (1) defering the upgrade. This alternative was not selected because it would decouple Itron IEE (Consumers Energy's MDM) from the Itron security infrastructure introducing application instability, security and dependency risks to the

utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Itron applications, creating more expense to support and no ability to leverage updated tool capability. (2) replacing the platform. Replacing IEE/MDM would require the application business owners to undertake a new initiative mirroring the expense and effort that went into the initial multi-million dollar project.(3) performing the upgrade is the best alternative. This option is superior for both customers and the Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.

- The **ISIS Papyrus 2026 Upgrade** project requires $328,999 in capital ($263,199 ROM Adjusted Capital) and $114,044 in O&M in the test year.

  - **Description:** This project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The ISIS Papyrus application is critical to creating electronic and paper correspondence for customers, including bills and dunnings.

  - **Problem Statement:** The application will be at least 1 major upgrade revision behind by 2026. It's imperative that customers retain unfettered access to their paper bills, dunning notices, and other communications produced by ISIS. ISIS also makes customer bills available for online viewing through the website and mobile apps. Without the upgrade, vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity, and security will be forthcoming. The upgrade will address these problems and challenges, as well as ensuring all other platform components comply with the Company's operational and security standards.

  - **Objectives:** The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors.

  - **Scope:** The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications.

  - **Alternatives:** Alternatives considered include: (1) delaying the upgrade and continuing to operate with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching. (2) The Company instead decided to upgrade to the current version. This alternative was chosen as it eliminates the risk of application instability and the inability to maintain cyber security patching.

- The **Rate Change Maintenance** project requires $184,667 in O&M in the test year.
    - **Description:** The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements.
    - **Problem Statement:** For the Company to continue to meet and comply with certain MPSC requirements and to enable it to update its rates when rate changes are approved, there is a need to make periodic updates/modifications to existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers.
    - **Objectives:** The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that include new surcharges, price changes, and energy efficiency programs.
    - **Scope:** The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Company's back-end system for more efficient rate changes.
    - **Alternatives:** Alternatives considered include: (1) a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and the time it would take for testing of this model; and (2) Instead, the Company chose to leverage onshore resources to plan, coordinate, and execute the rate changes. This option was selected as it supports the Company's operation model for rate changes**.**
- The **SAP Support Pack Upgrade 2026** project requires $410,658 in O&M in the test year.
    - **Description:** The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for business partners.
    - **Problem Statement:** To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing

vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability.

- **Objectives:** The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability, and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility.

- **Scope:** The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component ("ECC"), Customer Relationship Manager ("CRM"), Enterprise Portal, Process Orchestration ("PO"), Business Warehouse ("BW"), Business Objects ("BOBJ"), Data Services ("DS"), Solution Manager, Data Quality Manager ("DQM"), Graphical User Interface ("GUI"), Single Sign On ("SSO"), System Landscape Directory ("SLD"), and other related SAP applications.

- **Alternatives:** Alternatives considered include: (1) dividing the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) migrating to SAP S/4HANA. This option was not selected because SAP S/4HANA is a multi-year project that is not expected to be completed by year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3)Ultimately, the Company chose to balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.

- The **SiteCore Secondary Upgrade 2027** project requires $20,308 in O&M in the test year.

  - **Description:** The project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for the consumersenergy.com website, a channel many customers use for accessing account information and bill payment.

  - **Problem Statement:** Sitecore requires regular upgrades to adhere to the vendor's support lifecycle to ensure system reliability, take advantage of new application features, maintain current security updates, and improve the customer's website experience.

- **Objectives:** The project will add value for the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to-date security posture; and (3) supporting the Company's CXI (Customer Experience Index) goals by improving reliability and performance.

- **Scope:** The project scope is to upgrade the Sitecore content management software to the latest available version.

- **Alternatives:** Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the need to prevent the application from falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Migrating to a cloud solution was also considered. This alternative was not chosen due to the cost/benefit analysis of re-architecting the Company's current Sitecore implementation to facilitate cloud migration that is not viable at this time; and (3) Rejecting these alternatives, the Company chose to upgrade Sitecore on a two-year cycle because it provides up-to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.

Q. Please describe Confidential Exhibit A-23 (SHB-8).

A. Confidential Exhibit A-23 (SHB-8) is a confidential exhibit that provides Application Currency Program projected capital and O&M spend and scope for each of the Application Currency projects. Specifically:

- Column (a) provides the application name;
- Column (b) provides a disaster recovery tier, where applicable;
- Column (c) provides total projected 2026 capital expenditures;
- Column (d) provides total projected 2026 O&M expense;
- Column (e) provides total projected 2027 capital expenditures;
- Column (f) provides total projected 2027 O&M expense;
- Column (g) provides total test year capital expenditures;

- Column (h) provides total test year O&M expense;
- Column (i) provides the electric allocation for test year capital expenditures; and
- Column (j) provides the electric allocation for test year O&M expense.

Application Currency information can be used to exploit known security vulnerabilities; therefore, the exhibit is confidential.

Q. How does the Company decide which applications to include in the Application Currency Program for the test year?

A. The Application Currency Program focuses on upgrades that maintain security and reliability of the application and underlying platforms, as well as maintaining vendor supported software versions. Not every application requires an upgrade each year, so the application data provided in Confidential Exhibit A-23 (SHB-8) is not inclusive of all applications that are in upgrade cycles beyond the test year. The Company considers the following when determining the next upgrade version:

- Compatibility with the current environment and underlying platforms;
- Compatibility with associated or integrated applications;
- Future planned changes that could sub-optimize the application;
- Cyber security drivers and requirements;
- Additional functionality offered with the new version; and
- Availability of the appropriate version.

The applications meeting the criteria for upgrade are then added to the application currency list, cross-checked against other current or future projects that may impact the upgrade, and then scheduled.

Q. Please explain the Application Currency projects.

A. The following describes the Application Currency projects:

- The **Application Currency - Capital** and **Application Currency - O&M:**
  - **Description:** These initiatives will utilize capital and O&M funding to keep applications current for security and reliability. O&M is included with capital projects to complete expense activities associated with capital upgrades.
  - **Problem Statement:** The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.
  - **Objectives:** Maintaining the appropriate versions of applications through application currency upgrades adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.
  - **Scope:** The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes.
  - **Alternatives:** Applications are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing

their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

Specific spending requirements for each Application Currency project are indicated in the table below and supported with additional detail in Confidential Exhibit A-23 (SHB-8).

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Projected Test Year O&M
Application Currency-Corporate-Capital	$62,876	$50,301	$5,306
Application Currency-Corporate-O&M	$0	$0	$180,634
Application Currency-Customer-O&M	$0	$0	$69,663
Application Currency-Electric & Gas Shared-Capital	$48,975	$39,180	$217,312
Application Currency-Electric & Gas Shared-O&M	$0	$0	$317,806
Application Currency-Electric-O&M	$0	$0	$287,098
Application Currency-IT/Digital Foundation-Application Platforms-Capital	$97,409	$77,927	$97,268
Application Currency-IT/Digital Foundation-Application Platforms-O&M	$0	$0	$156,695
Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	$0	$0	$22,229
Application Currency-Operational Technology-Capital	$80,841	$64,673	$22,920
Application Currency-Operational Technology-O&M	$0	$0	$187,262
Application Currency-Security-Capital	$73,370	$58,696	$6,632
Application Currency-Security-O&M	$0	$0	$209,175

Enhancement Projects

Q. Please describe Exhibit A-24 (SHB-9).

A. Exhibit A-24 (SHB-9) is the Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis. Page 1 provides a summary of enhancement projected and actual spend for the years 2020 through 2027. Specifically:

- Column (a) provides the year reference;
- Column (b) identifies the electric case where the projected or actual amounts were provided;
- Column (c) identifies the exhibit number where the projected or actual amounts were provided;
- Columns (d) through (k) identify the projected or actual capital amounts for each year; and
- Columns (l) through (s) identify the projected or actual O&M amounts for each year.

Page 2 provides an analysis of total actual and projected enhancements, total incremental annual worklist of enhancements, total annual demand, total Company cumulative worklist, and electric allocation cumulative worklist. Specifically:

- Column (a) identifies the categories used for analysis, where total amounts include both capital and O&M;
- Columns (b) through (i) identify the projected or actual amounts by year; and
- Column (j) identifies the projected amounts for the test year.

In further detail, by category, the Total Electric Projected and Actual/Projected Spend amounts are derived from Exhibit A-24 (SHB-9), page 1, which are the source for the figures indicated. The Total Company Incremental Annual Worklist, which is broken out in Exhibit A-25 (SHB-10), is defined as the total Company cost of planned enhancement requests received in the year indicated in Exhibit A-24 (SHB-9), page 2. The Total Electric

Allocation Incremental Annual Worklist provides the electric allocation of the total Company incremental worklist. The Total Electric Annual Demand is defined as the total fulfilled and unfulfilled enhancement demand for the year, calculated by the sum of Total Electric Actual/Projected spend and Total Electric Allocation Incremental Annual Worklist. Total Company Cumulative Worklist is defined as the year-over-year increase of unfulfilled enhancement requests. Total Electric Allocation Cumulative Worklist provides the electric allocation of the Total Company Cumulative Worklist.

Q. What is the purpose of Enhancements investments?

A. Enhancements are smaller, short-cycle technology efforts to implement new or improved functionality and provide the flexibility needed to respond to rapidly changing business and customer conditions. Enhancement requests typically emerge from new or changing business conditions, compliance requirements, customer feedback, automation efforts, waste elimination efforts, and other improvement ideas. Enhancements benefit customers and the Company through cost savings, cost avoidance, productivity improvements, safety improvements, efficiencies, mandated regulatory changes, and improved customer experience.

Q. Please describe Exhibit A-25 (SHB-10).

A. Exhibit A-25 (SHB-10) is the Enhancement Worklist Detail Report. It provides a summary of the Enhancements queue of work requests. Specifically:

- Column (a) provides the Enhancement open date, internally referred to as the Open Date of the request;
- Column (b) identifies the Number, which is used to internally track the lifecycle of the Enhancement request;
- Column (c) identifies the Type of request;
- Column (d) provides a Description of Work;

- Column (e) provides the Work State of Submitted, Screening, Qualified, and Approved;
- Column (f) provides the Portfolio that has requested the enhancement;
- Column (g) identifies the Associated Application, which is internally referred to as the Configuration Item, and is the application that will be changed with the Enhancement;
- Column (h) identifies the internal Requestor Department;
- Column (i) provides the Total Estimated Hours, which reflects the planning estimate of work hours entered prior to the start of work request; and
- Column (j) provides the estimated Cost.

Q. How does the Company track and manage enhancements?

A. The Company actively maintains a worklist of enhancements, Exhibit A-25 (SHB-10). Each enhancement is tracked in detail from idea to completion including steps for value justification, estimation, prioritization, final funding approval, execution, and closure. For an enhancement to seek funding approval, it must be qualified with a cost estimate and benefits to ensure the enhancement is ready for execution. Once approved for funding in cross-functional business team reviews, the enhancement is scheduled. When the enhancement begins execution, the status for enhancement records is updated by enhancement request coordinators through closure. This provides the Company with an auditable tracking method for every enhancement request.

Q. Please explain the historical demand for enhancements and the Company's projection for future enhancement demand.

A. The demand for enhancement efforts has grown an average of 49% over the past three years because of the increased need for automation efforts, focus on waste elimination and cost optimization, additional functionality requests to optimize aging applications, and enhanced functionality requests for newly implemented technology.

As of October 2024, the Company has a worklist (Exhibit A-25 (SHB-10)) of 639 Company-wide requests to improve multiple applications and systems. This well-known worklist demonstrates the high volume of demand for smaller technology efforts. Despite exceeding the projected spend in several previous years, the Company is unable to keep up with the growing demand for enhancements, as shown on Exhibit A-24 (SHB-9), page 2. The projected Total Electric Allocation Cumulative Worklist (Demand) for the test year is $17,999,226 (Exhibit A-24 (SHB-9), page 2, line 7, column j), while the Company is projecting $10,120,181 of Total Electric Projected Spend (Exhibit A-24 (SHB-9), page 2, line 2, column j). To recognize this increasing demand and better project Enhancement costs, the Company is projecting these costs by determining incremental enhancement demand for 2026 and 2027 based on a known worklist, plus applying a combination of historical demand and historical spend. The projected level of demand still outpaces projected spend, as indicated above.

Q. What methods is the Company using to ensure projected enhancement expenditures and expenses in the test year are reasonable and prudent?

A. The Company is using two methods to validate enhancement demand expenditures and expenses in the test year: (1) three-year historical average and (2) total cumulative demand. For the three-year historical average method, the Company calculated the actual three-year historical average for 2022-2024 of $9,564,426 plus known incremental work of $6,801,862 ($16,366,289) and compared it to the projected Test Year enhancement expenditures and expenses of $10,120,181. This validates Test Year projections are in line with historical spending and known incremental work. Then for the total cumulative demand method, the Company compared the Total Electric Allocation Cumulative

Worklist amount of $17,999,226, in Exhibit A-24 (SHB-9), page 2, line 7, column j, to the projected Test Year enhancement expenditures and expenses of $10,120,181. This comparison validates these projections are in line with the projected demand.

Q. Please further explain the Company's calculation for the cumulative worklist amount.

A. Projections for the total cumulative worklist in 2026 and 2027 are based on the three-year average annual increase to enhancement demand. As indicated, cumulative enhancement requests grew at an average annual rate of 17% over the past three years. As a result, the cumulative worklist for enhancements (Exhibit A-25 (SHB-10)) continues to grow year over year, as depicted on Exhibit A-24 (SHB-9), page 2, line 7. Validating the projected Enhancement spending based on a known worklist and a three-year historical average of actual spend is an indication that the Company's test year projected spend of $10,120,181 is reasonable and prudent.

Q. Please explain the Enhancements projects.

A. The following are the Enhancements projects:

- The **Enhancements - Capital** and **Enhancements - O&M** requires the capital and O&M in the test year as described in the table below.
  - **Description:** These projects will utilize capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included with capital projects to complete expense activities associated with capital enhancements.
  - **Problem Statement:** As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on

key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

- **Objectives:** The value of software enhancements lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the respective business areas.

- **Scope:** The scope of application enhancements encompasses: (1) making necessary system changes; and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide new functionality for business areas represented by each program.

- **Alternatives:** Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

Specific spending requirements for each Enhancement project are indicated in the table below.

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M
Energy Assistance Enhancements and Maintenance Annual Updates	$0	$0	$193,086
Product Family Enhancements-Corporate-Capital	$1,454,687	$0	$193,040
Product Family Enhancements-Corporate-O&M	$0	$0	$116,530
Product Family Enhancements-Customer-Capital	$2,365,309	$0	$107,817
Product Family Enhancements-Customer-O&M	$0	$0	$172,976
Product Family Enhancements-Electric & Gas Shared-Capital	$710,841	$0	$96,252
Product Family Enhancements-Electric & Gas Shared-O&M	$0	$0	$124,350
Product Family Enhancements-Electric-Capital	$1,597,161	$0	$242,126
Product Family Enhancements-Electric-O&M	$0	$0	$240,811
Product Family Enhancements-Application Platform Services-Capital	$502,706	$0	$102,957
Product Family Enhancements- Application Platform Services -O&M	$0	$0	$103,502
Product Family Enhancements-Infrastructure Platform Services-Capital	$432,985	$0	$261,025
Product Family Enhancements-Infrastructure Platform Services-O&M	$0	$0	$144,327
Enhancements-Security-Capital	$559,651	$0	$94,628
Enhancements-Security-O&M	$0	$0	$303,412

Digital Foundations and Capabilities Projects

Q. Please explain the Digital Foundations and Capabilities projects.

A. Below are the Digital Foundations and Capabilities projects:

- The **Data & Analytics Platform Rationalization** project requires $3,140,597 in capital ($2,512,478 ROM Adjusted Capital) and $538,611 in O&M in the test year.
    - **Description:** This project will optimize the Data & Analytics system landscape by creating connections, migrating data into Data Lake 2.0 ("DL 2.0"), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems

including SingleStore Data Lake ("SSDL"), SAP BW, SAP BOBJ, Native HANA, the BW Portal, and SAP BODS creates value by reducing the total cost of ownership associated with maintaining and supporting legacy systems.

- **Problem Statement:** The IT Data & Analytics legacy systems (SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS) are outdated, inefficient, and becoming duplicative in nature with the introduction of DL 2.0. If these legacy systems are not retired, they will continue to cost the Company money as major investments are needed to maintain and support them.

- **Objectives:** This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources.

- **Scope:** The project scope includes: (1) the assessment of the existing Data & Analytics platforms including SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organization change management; and (7) the retirement/decommissioning of the legacy platforms and applications.

- **Alternatives:** Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company's cloud strategy; (2) Lift and shift these on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces; (3) Migrate all data sources to DL 2.0 and retire legacy systems. This alternative was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.

- The **Digital-Infrastructure Automation** project requires $477,554 in capital ($382,043 ROM Adjusted Capital) and $159,902 in O&M in the test year.

  - **Description:** This project will automate the deployment, maintenance, and tear down or decommissioning of cloud and data center services, leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services while reducing operational costs.

- **Problem Statement:** As the Company uses cloud services to provide infrastructure for applications, the difficulty of manually deploying, maintaining, and decommissioning infrastructure, improving efficiency of the use of infrastructure, bolstering resiliency, maintaining security posture, and extending new capabilities increases significantly. The manual approach lengthens application implementation times and leads to inconsistent and/or incorrect deployment of infrastructure.

- **Objectives:** This project will create value by ensuring the Company's application infrastructure requirements are met through automation. Specifically, the project will create automation to deploy, maintain, and deprovision infrastructure in a modular fashion to be used by product teams to deploy, maintain, upgrade, and deprovision Company applications. Thus, the project will: (1) improve the efficiency of the use of infrastructure by allowing for infrastructure to be provisioned when needed, and deprovisioned when not needed; (2) bolster the resiliency of infrastructure by creating reusable resilient patterns and scalability for applications to use; (3) deploying and removing infrastructure securely; and (4) enhancing or extending automation for new cloud and data center services to support Company applications.

- **Scope:** The project scope includes: (1) procuring automation software; (2) building automation for cloud and data center services; (3) building resiliency and scalability into the services; (4) building security posture into the services; and (5) enhancing existing or extending automation for new services.

- **Alternatives:** Alternatives considered included: (1) manually deploying, maintaining, and decommissioning infrastructure to support Company applications. This alternative was not chosen because it has proven to be slow, costly, and error-prone; (2) manually improving the efficiency in the use of infrastructure. This alternative was not chosen because the Company does not have the necessary people to manually do this work at the scale necessary to support the Company's portfolio of applications; (3) manually bolstering resiliency. This alternative was not chosen because it has proven to be error-prone; (4) manually maintaining security posture. This alternative was not chosen because the Company does not have the necessary people to manually do this work at the scale necessary to support the Company's portfolio of applications; (5) manually extending new cloud services. This alternative was not chosen because the services become available faster than the Company can manually deploy them while meeting necessary standards and security postures; (6) and utilizing pre-built tooling without extension or development. This alternative was not chosen because pre-built tooling does not meet the necessary Company standards and security postures; (7) procure automation software and extend the software to meet Company standards. This alternative was selected because the combination provides the most cost-effective method for automation of

existing and new services at speed and scale while allowing the services to be deployed in a secure manner that meets Company standards.

- The **OT Datacenter Migration** project requires $3,343,208 in capital ($2,674,566 ROM Adjusted Capital) and $570,345 in O&M in the test year.

  - **Description:** The OT environment consists of systems supporting the control and monitoring of electric grid, electric generation, gas compression, and natural gas pipeline. These systems are critical for safe and reliable natural gas and electric delivery. The OT Datacenter Migration project enhances the Company's capabilities by co-locating to an enhanced datacenter at a vendor facility.

  - **Problem Statement:** The Company's current datacenter for the OT environment needs modernization and relocation from the Parnall Data Center. The current location is not the preferred location to house servers and systems critical to the control of the Electric Grid or Gas Pipeline due to the close proximity to a railway system. The climate conditioners in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns . The location of the datacenter in the basement of the Parnall building is nearby to the main water piping for the building. There have been instances of water infiltration in the past.

  - **Objectives:** This project creates value for the Company by significantly strengthening capabilities through: (1) mitigating legacy physical and location risks at the current Parnall site; (2) migrating the OT infrastructure to a modern, highly secured environment with redundancy in climate conditions; and (3) better datacenter facilities support with a guarantee of redundant power.

  - **Scope:** The scope of the project includes: (1) migration of the OT environment from the Parnall Data Center to a co-located vendor data center; (2) re-validation of the OT Production and Disaster Recovery procedures once migration is completed; (3) migration of IT systems required for supporting the OT environment; and (4) decommission the existing OT environment from the Parnall location.

  - **Alternatives:** The Company performed an analysis of alternatives to expand capabilities as well as address constraints and risks: (1) Remain at the current Parnall Data Center; (2) migrate OT environments to the Cloud; and (3) relocate to a third-party co-location facility. Current industry best practices do not recommend migration of OT environments to the cloud. The co-location vendor provides the building, cooling, power, and physical security the Company lacks for its servers, storage, and other computing and networking equipment at the current Parnall location. Based on the analysis, the Company decided to implement the third alternative.

Q. Please explain the SAP HANA Database Migration project.

A. The SAP HANA Database Migration project has the following synopsis:

- **Description:** In preparation for SAP's planned end of support for its Business Suite product in 2027, the Company will migrate its existing SAP databases from Oracle to SAP HANA in advance of the required move to S/4HANA.

- **Problem Statement:** The Company's SAP applications currently utilize Oracle's relational database management system as their underlying database storage technology. SAP has informed its customers that standard support for its legacy Business Suite (aka ECC) product will end in 2027, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the Company will migrate all of its SAP databases off of Oracle and onto SAP HANA.

- **Objectives:** This project lays the groundwork for the Company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027.

- **Scope:** Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures, and tools required to manage the newly migrated SAP HANA applications.

- **Alternatives:** Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering no other options for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform a direct migration from SAP Business Suite on Oracle to S/4HANA. A direct migration to S/4HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application's functionality would change simultaneously, so this alternative was not selected; (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S/4HANA. It will also require the Company to accept

significant risk due to the fact that SAP security patches, application patches and upgrades will not be available upon termination of the SAP maintenance agreement; (3) Migrate to SAP's SaaS implementation of S/4HANA. This alternative was not selected because an S/4HANA SaaS migration is a much more disruptive option as the Company's business processes must be adjusted to accommodate functionality differences between ECC and S/4HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. The selected alternative to migrate the SAP databases to HANA prior to implementing S/4HANA gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process changes required with S/4HANA.

Q. What is the Company's migration timeline for the SAP HANA Database Migration project?

A. The Company initiated the SAP HANA Database Migration project in April 2023 and is anticipated to be completed by December 2025. The migration will be staggered across 2024 and 2025. In 2024, the Company migrated ancillary systems to HANA to gain valuable insight from these migrations and address any technical issues before migrating the ECC in 2025. This will also provide time to conduct mock migrations for ECC, which will help minimize downtime.

Q. Please explain the SAP S/4HANA Implementation project.

A. The SAP S/4HANA Implementation project has the following synopsis:

- The **SAP S/4HANA Implementation** project requires $43,491,363 in capital ($34,793,090 ROM Adjusted Capital) and $15,178,194 in O&M in the test year.
  - **Description:** This project will modernize the Company's current SAP ERP solution. Upon completion, the solution will provide enhanced functionality across several business areas while providing a supported and secure platform capable of business transformation**.**
  - **Problem Statement:** The current SAP ERP system will reach the end of mainstream vendor maintenance on December 31, 2027. Operating the system beyond the end of support date creates significant risks to comply with regulatory mandates, perform core customer supporting business operations, and apply the latest security patches that are critical for cyber

protection against customer and employee data breaches. In addition, an unsupported platform limits improvement of operational efficiency and maintaining the stability, reliability, and security of the system.

- **Objectives:** The S/4HANA program will position the Company for business transformation by enabling it to (1) provide and maintain capabilities for protection of sensitive customer and employee data; (2) provide enhanced system stability and reliability needed in a 24x7 business by significantly reducing system maintenance outages; (3) mitigate the regulatory and operational risks of running critical business processes on an unsupported platform; (4) implement simplified workflows and standardized processes by reducing customizations; and (5) use in-memory computing with embedded real-time analytics to make smarter, faster decisions.

- **Scope:** The project scope includes (1) Migrating the current SAP ERP solution to the latest S/4HANA solution. This includes (a) moving to the latest version of the software, (b) migrating existing data to the new S/4HANA data model, (c) connecting interfaces from other systems into S/4HANA, (d) using newer user interfaces available in S/4HANA where feasible, (e) setting up users and user access in the new system, (f) migrating existing reports and analytics or replacing them with new in-built reports and analytics in S/4HANA, and [redacted] (2) Enabling an architecture that minimizes downtime for system maintenance activities. (3) Implementing solutions where existing SAP ERP functionality is not available in S/4HANA. (4) Implementing a foundational "clean core framework." This requires minimizing or remediating custom code and utilizing SAP customization best practices in the new version. These best practices will decouple the core SAP software from Company-specific customizations, hence making it "clean." This clean core framework is expected to reduce the effort and cost of upgrading SAP in subsequent releases.

- **Alternatives:** An analysis was completed that included key industry input, feedback from business areas across the Company, technology leaders, and subject matter experts. This presented the organization with several alternatives, including the following: (1) Postpone the decision and stay on the current version. This would require purchasing the extended maintenance until 2030 due to the current mainstream maintenance expiring in December 2027. A skill shortage is anticipated as SAP customers scramble to meet the 2030 deadline. Delaying the Company's decision to migrate to S/4HANA would put the Company at a higher risk of securing those high-demand skilled resources. Staying on the current version beyond 2030 with third-party support would limit the Company's ability to continuously improve operational efficiency and maintain the stability, reliability, and security of the system. This alternative was not selected

because of the additional cost and risk, and the inability for the Company and its customers to enjoy any added benefits or new application features; (2) Eliminate SAP and use multiple best of breed solutions in the various business areas. (3) Eliminate SAP and implement a new ERP solution. SAP is currently used across the Corporate, Work and Asset Management, and Customer areas. There are very limited options for a single ERP system that provides all three areas of functionality. The current SAP system has over 100 satellite systems and around a thousand interfaces. Non-SAP alternatives may not work with current satellite systems, requiring the replacement or significant remediation of those satellite systems. These non-SAP alternatives would require a much larger change management initiative, significant reskilling of technical resources, and retraining of people across the Company who have become familiar with SAP over the last 16 years. Alternatives (2) and (3) are more expensive, complex to implement and support long-term, therefore were not chosen; (4) Migrate to the latest S/4HANA solution before the end of 2030. This option was chosen because it mitigates risks and provides a supported and secure platform capable of business transformation.

Q. Describe the deployment approach the Company will utilize for the SAP S/4HANA Implementation project.

A. The Company will deploy the migration to the new S/4HANA solution in phases to reduce the risk of operational impact to customers and co-workers. The Company will adopt SAP's standard Activate methodology for the deployment approach.[5] The Activate methodology includes six phases: Discover, Prepare, Explore, Realize, Deploy, and Run/Adopt. The Discover, Prepare, and Explore phases result in the design, which is then built, tested, and deployed in the Realize, Deploy, and Run/Adopt phases. The approach is to design the system holistically, meaning the Discover, Prepare, and Explore phases will cover all modules of SAP, including Finance, Supply Chain, HR, Work Management, and Customer. This ensures the system is designed optimally from end to end. Once the design

[5] Available at https://learning.sap.com/learning-journeys/discovering-sap-activate-implementation-tools-and-methodology/describing-sap-activate

is complete, the Company will conduct multiple iterations of the Realize, Deploy, and Run phases to deploy functional modules in a staggered capability deployment approach.

Q. Please explain the different S/4HANA migration alternatives considered.

A. The Company considered three migration alternatives: (1) Build a new SAP system without using any existing customizations, configurations, processes, or data (Greenfield); (2) Upgrade the existing SAP system, retaining existing customizations, processes, and data, then remediate errors that arise in the upgrade process in a series of iterations (Brownfield); and (3) Adopt a hybrid strategy, building a new SAP system, while selectively migrating critical data and process from the existing system (Bluefield).

Q. Which S/4HANA migration approach has the Company selected?

A. The Company has selected the hybrid or Bluefield approach for the S/4HANA Implementation project.

Q. Why did the Company select the Hybrid, or Bluefield, migration approach for the S/4HANA Implementation project and not the others?

A. The Company chose the Hybrid, or Bluefield, approach because it offers the best balance of lower risk and cost.[6] While the Greenfield option provides lower total-cost-of-ownership and faster time-to-value for implementations that want to shed a lot of legacy customizations and start afresh, this is not fully the case for the Company because the current system has many essential customizations in the customer billing and employee payroll areas that will need to be rewritten in the new system with this approach. Rebuilding customizations introduces significant risk and cost. Similarly, the Brownfield approach could provide a shorter project timeline by migrating all the current customizations and

[6] Available at https://www.leanix.net/en/wiki/tech-transformation/s4hana-greenfield-vs-brownfield-approach

processes. However, this approach is not preferred in the Finance, Supply Chain, and Work Management areas where the current system has a lot of custom processes, workflows, enhancements, and interfaces that are suboptimal compared to the standard best practice processes that come in S/4HANA. The Brownfield approach is also not preferred because the processes and data model in Finance and Supply Chain have changed significantly. Upgrading current customizations to the new system would not be easy and rewriting them would be expensive and increase risk. This would result in a new system that does not conform to SAP's clean core approach and would be expensive to upgrade in the future. Therefore, the ideal approach is a combination of the two where the new system adopts a Greenfield approach for Finance, Supply Chain and Work Management, and a Brownfield-like approach for Customer and Payroll.

Q. Why is the Company undertaking the expense and effort of migrating to the SAP S/4HANA version at this time?

A. Migrating to the SAP S/4HANA version is crucial for the Company because the mainstream support for our current SAP version ends in December 2027. After evaluating the project, the Company determined it will take approximately three years to complete. Assuming the Company begins the project in 2025, the timeline will extend into 2028, requiring the Company to purchase extended SAP support for 2028. It is important to note that extended support for the Company's current SAP version is only available until 2030.

Q. Will the Company's SAP systems face an increased risk of cyber-attacks if the S/4HANA project is not executed?

A. Yes. The Company's SAP systems will face increased risk of cyber-attacks if the S/4HANA project is not executed, because SAP has stated that after maintenance ends,

standard patches will no longer be available for SAP customer-specific maintenance, leaving the Company's SAP systems vulnerable to emerging threats from bad actors exploiting known vulnerabilities.[7]

Q. Please explain whether the Company's SAP systems will continue to operate if the S/4HANA project is not executed?

A. The Company's SAP systems will continue to operate with significant risk for an indeterminate period of time if the S/4HANA project is not executed. SAP will not support the Company's current SAP version after December 2027, when the mainstream maintenance ends. After this period, the risk of operational disruptions will increase significantly due to the lack of a Service Level Agreement with SAP, and there will be no guarantee that SAP resolve any new issues that arise.

Q. How did the Company develop the cost estimate for the SAP S/4HANA Implementation project?

A. The Company developed the cost estimate for the SAP S/4HANA Implementation project with the support of an independent third party that specializes in preparing for S/4HANA upgrades. The cost estimate consists of labor, contractor, software, and non-labor costs.

The labor and contractor cost estimates were derived as follows:

- First, the phases of the project were laid out in a timeline based on the phased deployment approach and Hybrid migration approach, both previously described in my testimony.
- Second, the high-level scope was identified, including the processes, pain points, customizations, integrations, roles, and data volumes that need to be migrated to S/4HANA.

[7] Available at https://support.sap.com/en/my-support/knowledge-base/security-notes-news.html?anchorId=section_370125364.

- Third, the effort for the design and subsequent phases were translated into the number of hours and resources required for each phase. The resources are further broken down into roles and number of each role.

- Lastly, the resource estimates were assumed to be a mix of 30% internal employees and 70% external contractors. The Company then applied an average resource rate based on internal and external resources to calculate the cost estimate. For certain activities, the resource estimate was derived using a percentage of the overall effort based on best practices, e.g. program management and quality management.

- The software cost estimate was based on indicative Bill of Material ("BOM") from SAP.

- The non-labor cost estimates are based on business expense, and labor overheads based on projected internal labor and external contractor costs to support the project.

Finally, the Company conducted a comparison of peer utility overall cost estimates and duration for their S/4HANA implementation projects to validate the Company's overall cost and duration estimate was reasonable.

Q. Why is this SAP upgrade more costly than the Company's previous upgrades?

A. This SAP upgrade is more costly than the Company's previous upgrades for several reasons. First, the latest SAP S/4HANA version improves business processes, requiring the Company to thoroughly evaluate these best practices against existing processes. This evaluation is crucial in determining adoption and adds to the overall project cost.

Second, migrating data to the new system involves mapping, transforming, and testing data elements required by S/4HANA's new data model. Third, the Company must re-evaluate and update user access because the system controlling access permissions has changed in S/4HANA. Fourth, the existing solution has customizations that cannot be moved to the new system as-is due to the differences in business processes, data model, and permissions. Finally, SAP recommends customers adopt a "clean core" approach when customizations are necessary. This approach moves the customizations outside the core

product, which makes future upgrades easier. This requires the Company to perform a detailed evaluation and remediation of existing customizations.

Q. Would it be more cost-effective for the Company to replace its SAP systems?

A. No. It would not be more cost-effective for the Company to replace its SAP systems. This would require re-engineering the entire SAP system to a new solution, assuming that the current system could be replaced with a single replacement. It would require significant effort to re-skill the Company's co-workers, re-engineer business processes, re-implement the system, and integrate the new system with all the systems currently interfacing with SAP. The Company currently has more than 1,000 interfaces to SAP. Replacing SAP with multiple systems would be more costly and introduce additional risk due to the complexity of managing multiple disparate solutions. The Company would need to develop integrations between systems like Finance, Supply Chain, Work Management, and Customer. These integrations are inherent in an integrated solution such as SAP.

Q. Is the Company requesting any special rate-making treatment to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project?

A. Yes. The Company is requesting to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project over a 15-year asset life. This software asset will provide significant value and functionality over an extended period, as it is deeply integrated into the Company's business processes, and there is a substantial investment in its development and integration. The benefits of continuing to use the existing software outweigh the costs of transitioning to new software sooner than

15 years. This approach will also benefit customers by spreading these costs over 15 years to minimize the impact on customer rates.

Q. Please describe Confidential Exhibit A-26 (SHB-11).

A. **Confidential** Exhibit A-26 (SHB-11) is the IT S/4HANA Cloud Implementation Costs balance for Electric and Common investments for the projected 13 months ending April 30, 2027. It provides a summary of the electric allocation of projected IT Department investments expenditures. Specifically:

- Column (a) provides the balance category;
- Columns (b) through (n) provide each month's ending IT S/4HANA Cloud Implementation Costs balance; and
- Column (o) provides the 13-month average of columns (b) through (n).

Q. Please describe the purpose of Confidential Exhibit A-26 (SHB-11).

A. The Company has identified cloud computing as a viable alternative for several technology solutions associated with the SAP S/4HANA Implementation project. As discussed previously, the Company is requesting to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project over a 15-year asset life and adjusting working capital. Cloud implementation costs are projected based on the planned implementations of the SaaS solution associated with the SAP S/4HANA Implementation project. This working capital adjustment is provided by Company witness Daly on Exhibit A-12 (PDD-34), Schedule B-4.

Q. Is the Company requesting any additional special rate-making treatment for the SAP S/4HANA Implementation project's IT Investments O&M expense?

A. Yes. The Company is also requesting to defer the IT Investments O&M expense associated with the SAP S/4HANA Implementation project and recover the expense over the life of

the asset. This approach will benefit the customers by spreading these costs over the life of the asset to minimize the immediate impact on customer rates. This proposal will be discussed further in the direct testimony of Company witness Daly.

Q. Are there any Digital Foundations and Capabilities projects with disallowances from Case No. U-21585 that you would like to discuss?

A. Yes. The following Digital Foundations and Capabilities projects are addressed below.

- IT Operations Management - Service Operations;
- Operational Technology - Service Management Upgrade;
- Software Asset - Service Management Upgrade; and
- SolarWinds Performance Monitoring Expansion Upgrade.

Q. Please briefly describe the IT Operations Management - Service Operations project.

A. This project provides the Company access to a service mapping tool that leverages infrastructure data to identify all assets that support a service, with information about the service-specific relationship.

Q. Please briefly describe the Operational Technology - Service Management Upgrade project.

A. This project provides the Company service management capabilities for Operational Technology, to automate asset tracking, maintenance, and incident management for the operational technology assets.

Q. Please briefly describe the Software Asset - Service Management Upgrade project.

A. This project will give the Company automated monitoring, assessment, and oversight of software licenses and compliance to optimize software license management.

Q. Please briefly describe the SolarWinds Performance Monitoring Expansion Upgrade project.

A. This project provides the Company an IT observability and monitoring solution that provides an aggregate view of IT system availability and performance.

Q. What was the partial disallowance for the four Digital Foundations and Capabilities projects discussed above in Case No. U-21585?

A. The partial disallowance for the four Digital Foundations and Capabilities projects discussed above in Case No. U-21585 was a 20% disallowance of the 2024 projected amount ($444,197) of $88,839.

Q. What was the Commission's reason for partial disallowance of the four Digital Foundations and Capabilities projects 2024 projected amounts?

A. The Commission's reason for partial disallowance of the four Digital Foundations and Capabilities projects is the projects' 2024 projected cost estimates of $444,197 was not adequately supported.

Q. Did Staff oppose the four Digital Foundations and Capabilities projects?

A. No. Staff did not oppose the four Digital Foundations and Capabilities projects.

Q. Is the Company requesting full recovery of the actual 2024 costs for the four Digital Foundations and Capabilities projects in this case?

A. Yes, the Company is requesting full recovery of the actual 2024 costs provided in the table below for the four Digital Foundations and Capabilities projects in this case.

Project	Capital 2024 Actuals	Confidential Exhibit A-20 (SHB-5) Reference
IT Operations Management – Service Operations	$139,403	Line No. 73, column l
Operational Technology – Service Management Upgrade	$115,849	Line No. 75, column l
Software Asset – Service Management Upgrade	$49,003	Line No. 82, column l
SolarWinds Performance Monitoring Expansion Upgrade	$2,743	Line No. 84, column l

Security Projects

Q. Please explain the Security projects.

A. Below are the Security projects:

- The **Business Continuity - Program Management Tool** project requires $50,579 in O&M in the test year.
  - **Description:** The Business Continuity Program Management Tool is critical for successful and effective Business Continuity, Disaster Recovery, and Emergency Management Programs. The software tool will provide automation, enhance the Company's incident management processes, establish critical linkages between departments and essential functions they support, and will perform necessary analysis before, during, and after a disruption that allows for the efficient response to minimize downtime.
  - **Problem Statement:** The current business continuity and disaster recovery program management tool does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. The current tool limits automation opportunities and has gaps in how it handles template enhancements, which results in the need for manual workarounds in order to prevent losing critical data. The lack of capability affects reporting, upstream/downstream impact mapping, Incident Command System ("ICS") documentation automation, and user administration.
  - **Objectives:** This project will create value for the Company by: (1) maintaining the documentation that supports the recovery efforts of critical processes and associated essential functions that, if disrupted, would present significant impact to the Company and customers; (2) limiting business and community impact while providing a critical energy service; (3) prioritization of the recovery of critical processes and resource allocation during a business continuity incident(s); (4) providing a consistent, organized, and expedient response process (ICS) that is flexible to meet the needs of any incident, regardless of severity or scope; (5) providing a mechanism for identifying restoration gaps between critical

business processes and IT recovery capabilities; (6) reducing or eliminating human error and waste; and (7) improved and more efficient user experience.

- **Scope:** The project scope includes: (1) framework for the development and maintenance of Business Continuity, System (Application) Recovery Plans, ICS, and Disaster Recovery Plans that are effective and easily accessible during an event; (2) automation for reporting to track status and to measure effectiveness and maturity of the program (Business Continuity, Emergency Management, Disaster Recovery Programs); (3) component for facilitating effective training exercises and response efforts through incident management tools that utilize concepts from the Federal Emergency Management Agency ("FEMA") National Incident Management System ("NIMS"); (4) program management tools to monitor required program deliverables; (5) template for developing and maintaining site hazard assessments; (6) dependency mapping of critical business processes and IT applications; and (7) integrated business impact analysis process.

- **Alternatives:** Alternatives considered included: (1) continue to use Riskonnect (current Disaster Recovery tool). This alternative was not selected because it currently does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption; (2) Revert back to manual process. This alternative was not selected because the manual process is time consuming; and leads to human struggle and duplicative work. A previous KPMG Audit of the Business Continuity Program indicated the need for interdependency mapping and a software tool is the best way to accomplish this; (3) Implement a best-in-class SaaS solution to address the current incident management gaps and provide a consistent, organized, and expedient response process that supports the FEMA ICS. This alternative was selected because there are better SaaS solutions that fit the needs outlined above.

- The **Forward Web Proxy Services** project requires $2,048,658 in capital ($1,638,926 ROM Adjusted Capital) and $201,735 in O&M in the test year.

  - **Description:** This project will replace the current web proxy service platform with a new platform. A web proxy service is a type of proxy server that sits between a client and the internet. It acts as an intermediary that evaluates, modifies, and forwards the client's requests to the destination web server. This service offers many benefits for the Company such as advanced filtering. Advanced filtering in a forward web proxy service can filter out unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of attacks such as ransomware.

- **Problem Statement:** The Company currently leverages an existing vendor platform for web proxy services that has been in existence since 2021. Since the implementation of the platform, it has caused ongoing operational issues related to web filtering and connectivity. When there is a degradation of service, Company employees and contractors are unable to access internet or cloud-based resources. As the Company continues its cloud and SaaS journey, it is imperative to provide consistent access and communication, while still protecting the Company from cyber threats.

- **Objectives:** This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilizing technology to enable the Company to handle all types of different workloads from varying geographic locations and is highly available; (3) using a mature and scalable web proxy service provider; and (4) providing Zero Trust by continuously verifying every connection request.

- **Scope:** The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; and (3) potentially changing SaaS cloud vendors.

- **Alternatives:** The Security team did extensive research on alternative web proxy services solutions. Alternatives considered included: (1) continue to use and maintain the current web proxy services platform. This alternative was not chosen due to the consistent operational issues with the platform that make it unreliable. The result of an unreliable system means that employees and contractors are unable to access business critical services such as email, Teams, ServiceNow, and SharePoint Online; (2) route all internet traffic through the Company's corporate data center. This alternative was not chosen because the capabilities of firewalls are not as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) replace current system with modern vendor platform for web proxy services. The option that was chosen is to replace the current solution with a new system. This option was chosen because it offers additional features such as browser isolation (the ability to contain web pages so that the web page cannot affect the client workstation) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation, the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's capabilities.

- The **Physical Access Management and Alarm Response** project requires $1,832,660 in capital ($1,466,128 ROM Adjusted Capital) and $168,119 in O&M in the test year.

  - **Description:** The project will replace the Company's Physical Access Management System to establish a centralized platform that manages user

identities, authenticates users, authorizes access, and audits user activities. The intent of this project is to consolidate and modernize the Company's physical security systems that will enable enhanced security monitoring to prevent unauthorized entry into sensitive corporate areas while providing increased flexibility to the Company's valued employees and contractors.

- **Problem Statement:** The Company's Security Fusion Center (the Fusion Center is the Company's combined physical and cyber security operations center) is experiencing operational issues with the current physical access management system. The installation is out of date and causes inconsistent behavior when given tasks by automations within the Company's Identity Management solution. Frequent issues have been reported related to frozen jobs in the Company's existing access management solution due to the current system's database. This results in significant waste in the form of (1) waiting, the business partner is waiting much longer than they should have for the system to process their request as un-freezing jobs is a manual process; (2) lost productivity, that waiting can cause for the business partner as it can either prevent them from accessing sites they need, or slow them down unnecessarily while they work with others to be escorted; (3) rework, because frozen jobs do not always run correctly when unfrozen, meaning the business partner has to resubmit their request and/or Identity Operations has to do additional work to satisfy the original request; and (4) alarms can cause a frozen state that impact system stability and reduces security visibility as a result. Not moving to new technology also carries a growing risk of outright system failure which could result in unauthorized physical access and/or impact the Company's ability to efficiently function. The current installation of the physical access management system and the Company's current card readers do not support next generation physical access control methods, such as digital ID. This prevents the Company from adopting new methods and practices that can lower costs and improve control and responsiveness. All employees, contractors, staff, and visitors are impacted by the problem.

- **Objectives:** This project creates value for the Company by: (1) developing an alarm and event monitoring system, which will enable seamless orchestration of system alarms and cameras; (2) adding automation that will streamline remediation processes and orchestrate camera operations for efficiency; (3) refining access revocation and badge access management to ensure only authorized personnel have entry privileges; and (4) introducing new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company's facilities.

- **Scope:** The project scope includes modernizing the Company's current physical access control system, badge system, badge access hardware and firmware, and all 3000 card readers across facilities and assets. This will

require modernization of all physical badge access readers and the implementation of hardware and software necessary to run the physical access control system. In addition, there will be substantial automation and integration between the security orchestration solution and the physical access control systems to realize the full benefits of this initiative.

- **Alternatives:** Alternatives considered were: (1) Keeping the current physical access control system and processes as-is. This alternative was not selected as the current platform is outdated, increasingly expensive to support, and does not include modern capabilities, such as digital IDs. It also does not reduce waste, cost, and it does not improve speed to delivery; (2) Developing a custom, in-house physical access control solution that includes modern capabilities, such as digital IDs. This option was not selected as the Company lacks the expertise to build such a solution. Custom-developed solutions have higher long-term costs, and generally result in significant waste, as well as lower speed to delivery; and (3) Implementing a new physical access control system that includes modern capabilities, such as digital IDs, that reduces waste and cost and improves speed to delivery. There are vendors in the market that specialize in physical access control systems that offer proven capabilities the Company is looking to implement. This option was selected as it will allow the Company to meet its objectives of lower waste, lower cost, improved speed to delivery, by implementing digital IDs and enabling tighter integration between the physical access control system and the Company's other security platforms.

- The **Saviynt Enterprise Identity Governance and Access ("EIGA") Implementation** project requires $432,685 in capital and $24,936 in O&M in the test year.

  - **Description:** The project will implement Saviynt EIGA module, consolidate Identity Access Management ("IAM") functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications.

  - **Problem Statement:** The current version of AccessNow reached end-of-life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and

customizations. While beneficial for end users, these integrations increase the risk of system failures, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduces failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention.

- **Objectives:** This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt EIGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) Minimizing custom code and focusing on configurations only by utilizing out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface.

- **Scope:** This project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Standardizing processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access system; (4) Addressing issues with aging applications, multiple IAM platforms, integration challenges, and antiquated HR processing.

- **Alternatives:** Alternatives considered include: (1) Implementing hot fixes to AccessNow version 8.1.5 to ensure support through mid-2023; (2) Upgrading only the application to current supported version, excluding the new web portal but will include new application functionality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break/fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating AccessNow software.

- The **Security/OT Field Modernization** project requires $149,231 in capital ($119,385 ROM Adjusted Capital) and $45,452 in O&M in the test year.

  - **Description:** This project will implement new infrastructure for accomplishing improved security in the field for OT assets.

  - **Problem Statement:** Gas and Electric technicians are using corporate laptops, to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. Vendors and

contractors have access to the Company's critical infrastructure using non-Company laptops. The best practice is to use dedicated laptops to connect to critical infrastructure.

- **Objectives:** The value of this project is deploying dedicated Company OT laptops and associated OT infrastructure that can move between OT locations only and providing a secure environment.

- **Scope:** This project will procure and configure approximately 130 devices that will be used to manage critical OT infrastructure.

- **Alternatives:** The Company reviewed several options to mitigate cyber security risks inherent with the use of standard corporate laptops managing critical infrastructure. The alternatives considered are: (1) Continue utilizing existing workflow of using Corporate domain laptops with software installed; (2) Bring in an outside vendor to design and implement a proposed infrastructure; (3) Complete disallowance of all local access to critical systems; (4) Extending the OT network to remote Company locations; (5) Deploy a dedicated Company OT laptop and OT communications circuits, which includes cellular connectivity. The dedicated OT laptop and communications circuits presented the best way to secure the critical infrastructure by limiting internet and e-mail access. Vendors and contractors could also utilize these approved dedicated systems for managing infrastructure they help support at Company locations. Based on the analysis performed, the Company chose to deploy a dedicated OT laptop and communications circuits.

Q. Overall, are the expenses and expenditures you have identified reasonable and prudent?

A. Yes. The O&M expenses and capital expenditures requested in this case will help the Company achieve the outcomes of the IRP and EDIIP, continually improve customers' interactions with the Company, and maintain a reliable and secure technology base that is exposed to ever-increasing and serious cyber security threats over time. Technology is the backbone of Company operations and two-way customer communications. The Company has demonstrated the prudency of project expenditures and operational O&M requirements.

I have also provided a detailed synopsis of each project, a supplementary exhibit of the total project cost, hard savings, and cost/benefit analysis for each project in the test year, and a deep dive into benefits for several high-priority projects. This project-specific information demonstrates how IT investments and operational expenses are helping the Company provide exceptional service to its customers. The Company is seeking full recovery for these IT costs that keep its systems available, customers safe from growing cyber security threats, and the Company on a path to the bright future it envisioned in its IRP and EDIIP – one powered by safe, reliable, affordable, clean, and equitable energy.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Stacy H. Baker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Stacy H. Baker who provided direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony and exhibits submitted by the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") and Attorney General witness Sebastian Coppola in this case concerning the Information Technology ("IT") Department's Operations and Maintenance ("O&M") expenses and capital expenditures. Specifically, I will respond to:

- Staff witness Emma Zichi's proposed adjustments to capital expenditures to correct errors discovered through audit and discovery;
- Staff witness Zichi's proposed adjustments to IT capital expenditures and IT Investments O&M for IT/Digital Foundation and Security projects;
- Staff witness Zichi's proposed recommendations for the SAP S/4HANA Implementation project;
- Staff witness Brittney Klocke's proposed adjustments to IT capital expenditures and IT Investments O&M expenses for the Product Family Enhancements-Customer-Capital project; and
- Staff witness Jessica Duell's proposed adjustments to IT capital expenditures to correct errors discovered through discovery for the Service Restoration Artificial Intelligence project.

I will also respond to Attorney General witness Coppola's proposed adjustments to IT capital expenditures and IT Investments O&M expenses.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes.

Exhibit A-183 (SHB-12)	Asset Refresh Program ("ARP")-Field Device Asset Management ("FDAM") and ARP-Workstation Asset Management ("WAM") New Purchases Four-Year Historical Average;
Exhibit A-184 (SHB-13)	Staff Audit Responses U21870-SA-CE-024 and U21870-SA-CE-090; and
Exhibit A-185 (SHB-14)	Asset Refresh Program-Field Device Asset Management for the replacements and new purchases for 2021, 2022, 2023, and 2024 including new purchases; and
Exhibit A-186 (SHB-15)	Staff Audit Response U21870-SA-CE-080.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

MPSC STAFF

Q. What project is Staff witness Zichi proposing adjustments for in this case?

A. On page 4, line 1, through line 17, of her direct testimony, Staff witness Zichi is proposing a partial adjustment for the ARP-Collaboration project.

Q. What amount is Staff witness Zichi proposing to adjust for the ARP-Collaboration project?

A. Based on Staff witness Zichi's Exhibit S-14.0, line 5, she is proposing a partial adjustment of $250,023 in the 12-month bridge period ending 12/31/2025, $46,300 in the 4-month bridge period ending 4/30/2026 and $138,902 for the projected test year ending 4/30/2027 of capital expenditures for the ARP-Collaboration project. This adjustment corresponds to the capital expenditures in Confidential Exhibit A-20 (SHB-5), lines 143, 217 and 295 and

is within the IT/Digital Foundation business category in Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5.

Q. Do you agree with Staff witness Zichi's proposed adjustment to the ARP-Collaboration project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit Response No. U21870-SA-CE-006 (Exhibit S-14.1, page 2) that the original projection for auditorium refreshes planned for 2025, 2026, and 2027 were based on costs to replace historical equipment. The Company was able to refresh the historical equipment at a lower cost than what was planned for 2025. Based on the revised cost estimates for Conference Room Refreshes, capital expenditures for 2025, 2026, and 2027 should be reduced by $250,023 in the 12-month bridge period ending 12/31/2025, $46,300 in the 4-month bridge period ending 4/30/2026 and $138,902 for the projected test year ending 4/30/2027 for the ARP-Collaboration project.

Q. What adjustments is Staff witness Zichi proposing for the ARP-FDAM project in this case?

A. On page 4, line 18, through page 5, line 4, of her direct testimony, Staff witness Zichi is recommending a full disallowance of all new device purchases for 2026 and 2027 included in the ARP-FDAM project.

Q. What amount is Staff witness Zichi proposing to adjust for the ARP-FDAM project in this case?

A. Based on Staff witness Zichi's Exhibit S-14.0, line 6, she is proposing a full disallowance of $228,567 for the 4-month bridge period ending 4/30/2026 and $658,700 for the projected test year ending 4/30/2027 of capital expenditures for the ARP-FDAM project. This

adjustment corresponds to the capital expenditures in Exhibit A-22 (SHB-7), page 5, line 3, columns (e) and (f) and is within the IT/Digital Foundation business category in Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5.

Q. What is Staff witness Zichi's rationale for proposing full disallowance of the new field device purchases for the ARP-FDAM project?

A. On page 5, lines 5 through 14, of her direct testimony, Staff witness Zichi provides the rationale that due to a lack of information provided by the Company through audit regarding the methods used to calculate the total projected costs for new purchases in 2026 and 2027, the costs should be fully disallowed.

Q. Did the Company provide the information and the method for projecting the new field device purchases costs?

A. Yes. The Company provided in audit response at Exhibit S-14.1, page 5 (U21870-SA-CE-008), that the Company projected the Total Company new purchases of $1 million for each 2026 and 2027, which was based on the historical spend. In the same audit response, the Company provided the historical actuals that were used to validate the reasonableness of the projected 2026 and 2027 new purchase costs for ARP-FDAM. The Commission's September 30, 2025 Order in Case No. U-21806, pages 119-122, agrees with the Company that its evidence supports its projected costs based on historical spending and projected need for new purchases for the ARP-FDAM project. The Commission also noted in the same order that they would have liked to see more specificity in cost projections for this program, which I will address later in my testimony.

Q. Does Staff find the method used by the Company for the projected 2026 and 2027 new purchase costs for ARP-FDAM problematic?

A. Yes. On page 5, line 15, through page 6, line 7, of her direct testimony, Staff witness Zichi provides that the method used by the Company for the projected 2026 and 2027 new purchase costs for ARP-FDAM problematic because the Company did not explicitly state in its audit response that the average of all four years of historical data was used to determine the total projected costs of the new field device purchases. Additionally, the Company stated that the projected costs were validated using historical costs. Staff further explains that the method does not provide certainty as the Company did not provide the calculation or the method used to validate the projected cost for new field device purchases.

Additionally, on page 6, lines 11 through 13, Staff provides that a full analysis cannot be completed of the projected new purchase costs if the Company does not share the methods or calculations used to project these costs.

Q. Does Staff believe that the purchase of new field devices for the ARP-FDAM is unnecessary?

A. No. On page 6, lines 8 through 20, of her direct testimony, Staff witness Zichi provides that Staff understands the importance of new field device purchases for this project and does believe the Company will spend the projected 2026 and 2027 costs for the ARP-FDAM project.

Q. Does the Company agree with the Commission and Staff that using a more explicit or specific method for projecting new field device purchases for the ARP-FDAM project would provide more certainty in the projected costs?

A. Yes. The Company agrees that using a four-year historical average for new field devices purchases and providing information about any adjustments would be a more explicit or specific method to calculate the total projected costs for new field device purchases for the ARP-FDAM project. I have provided information below and in Exhibit A-183 (SHB-12) that will permit this approach for this case, and the Company commits to using this method in future cases as well.

Q. Please describe Exhibit A-183 (SHB-12).

A. Exhibit A-183 (SHB-12) is the four years of historical actuals data for the Years 2021, 2022, 2023, 2024, and total Company and electric allocation four-year historical average calculations for the costs associated with new purchases of field devices and workstations for the ARP-FDAM and ARP-WAM projects. Specifically:

- Column (a) provides each historical year used in the total Company and electric allocation four-year historical average calculations;
- Column (b) provides the actual data for each historical year and the total Company and electric allocation four-year historical average calculations; and
- Column (c) provides a reference to the exhibits from prior cases where historical actual data was provided.

Q. Based on using a four-year historical average of 2021 through 2024 for new field device purchases does the Company have any adjustments for the projected 2026 and 2027 new purchases costs for the ARP-FDAM project?

A. Yes. Based on the electric allocation four-year historical average of 2021 through 2024 of $611,611 (Exhibit A-183 (SHB-12), page 1, line 6, column (b)) for new field device purchases the 2026 and 2027, projected costs should be reduced by $24,696 for the 4-month bridge period ending 4/30/2026 and $74,089 for the projected test year ending 4/30/2027 of capital expenditures for the ARP-FDAM project.

Q. What adjustments is Staff witness Zichi proposing for the ARP-WAM project in this case?

A. On page 6, line 21, through page 7, line 8, of her direct testimony, Staff witness Zichi is recommending a full disallowance of all new device purchases for 2026 and 2027 included in the ARP-WAM project.

Q. What amount is Staff witness Zichi proposing to adjust for the ARP-WAM project in this case?

A. Based on Staff witness Zichi's Exhibit S-14.0, line 7, she is proposing a full disallowance of $228,567 for the 4-month bridge period ending 4/30/2026 and $685,700 for the projected test year ending 4/30/2027 of capital expenditures for the ARP-WAM project. This adjustment corresponds to the capital expenditures present on Exhibit A-22 (SHB-7) page 15, line 10, columns (e) and (f) and is within the IT/Digital Foundation business category in Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5.

Q. What is Staff witness Zichi's rationale for proposing full disallowance of the new workstation purchases for the ARP-WAM project?

A. On page 7, lines 9 through 19, of her direct testimony, Staff witness Zichi provides the rationale that due to a lack of information provided by the Company through audit regarding the methods used to calculate the total projected costs for new purchases in 2026 and 2027, the costs should be fully disallowed.

Q. Did the Company provide the information and the method for projecting the new workstation purchases costs?

A. Yes. The Company provided in audit response at Exhibit S-14.1, page 7 (U21870-SA-CE-010), that the Company projected the Total Company new purchases of $1 million for each 2026 and 2027, which was based on the historical spend. In the same audit response, the Company provided the historical actuals that were used to validate the reasonableness of the projected 2026 and 2027 new purchase costs for ARP-WAM. The Commission's September 30, 2025 Order in Case No. U-21806, pages 122-124, agrees with the Company that its evidence supports its projected costs based on historical spending and projected need for new purchases for the ARP-WAM project. The Commission also noted in the same order that they would have liked to see more specificity in cost projections for this program, which I will address later in my testimony.

Q. Does Staff find the method used by the Company for the projected 2026 and 2027 new purchase costs for ARP-WAM problematic?

A. Yes. On page 7, line 20, through page 8, line 3, of her direct testimony, Staff witness Zichi provides that as stated for the ARP-project, the method used by the Company for the projected 2026 and 2027 new purchase costs for ARP-WAM does not specify that the

projections are based on historical actuals; rather, the new purchase costs are just validated by the historical actuals. Staff further explains that the Company did not use a calculation to project the new purchase total Company costs of $1 million, leaving Staff to question how the Company arrived at its projection for new workstation purchases.

Q. Does Staff believe that the purchase of new workstations for the ARP-WAM is unnecessary?

A. No. On page 8, lines 8 through 20, of her direct testimony, Staff witness Zichi provides that Staff understands the importance of new field device purchases for this project and does believe the Company will spend the projected 2026 and 2027 costs for the ARP-WAM project.

Q. Does the Company agree with the Commission and Staff that using a more explicit or specific method for projecting new workstations purchases for ARP-WAM project would provide more certainty in the projected costs?

A. Yes. The Company agrees that using a four-year historical average for new workstation purchases and providing information about any adjustments would be a more explicit or specific method to calculate the total projected costs for new workstation purchases for the ARP-WAM project. I have provided information in Exhibit A-183 (SHB-12) that will permit this approach for this case, and the Company commits to using this method in future cases as well.

Q. What is the total Company and electric allocation four-year historical average for 2021 through 2024 for new workstation purchases for the ARP-WAM project?

A. The total Company and electric allocation four-year historical average for 2021 through 2024 are $1,817,867 and $1,246,512, respectively (Exhibit A-183 (SHB-12), page 2, lines 5 and 6, column (b)) for new workstation purchases for the ARP-WAM project.

Q. Did the Company make any adjustments to the four-year historical average for new workstation purchases when projecting the costs for 2026 and 2027 of $1 million each year?

A. Yes. The actual new workstation purchases of $4,583,866 in 2021 were significantly higher than the projected 2021 new workstation projections of $1,611,867 in Case No. U-20963 Exhibit No. A-110 (JDT-9), page 9, lines 9-14 and 17–22 (estimated workstation portion of additional accessories, shipping and handling, etc. to be 81% of lines 21 and 22 ($60,657) or $48,813). The actual increase was due to additional workstation and monitor purchases to adhere to the Centers for Disease Control and Prevention guidelines for in-person work due to the COVID-19 pandemic. The Company considered this unique occurrence when projecting the new workstation purchases for 2026 and 2027 of $1 million each year.

Q. Based on using a four-year historical average of 2021 through 2024 for new workstation purchases, with the adjustments just described, does the Company have any adjustments to the projected 2026 and 2027 costs for the ARP-WAM project?

A. No. The four-year historical average and the adjustments just described was the method used to project 2026 and 2027 costs for the ARP-WAM project.

Q. What adjustment is Staff witness Zichi proposing for the Digital-Infrastructure Automation project in this case?

A. On page 8, line 17, through page 9, line 5 of her direct testimony, Staff witness Zichi is proposing a full disallowance for the Digital-Infrastructure Automation project.

Q. What amount is Staff witness Zichi proposing to adjust for the Digital-Infrastructure Automation project?

A. Based on Staff witness Zichi's Exhibit S-14.0, line 8, she is proposing an adjustment of $382,043 (Rough Order of Magnitude ("ROM") Adjusted) of capital expenditures and $159,902 of Investments O&M expense for the projected test year ending 4/30/2027 for the Digital-Infrastructure Automation project. This adjustment corresponds to the capital expenditures and Investments O&M expense in Confidential Exhibit A-20 (SHB-5), line 307 and is within the IT/Digital Foundation business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5 and Exhibit A-19 (SHB-3), page 1, line 3.

Q. What is Staff witness Zichi's rationale for proposing adjustments to the Digital-Infrastructure Automation project?

A. On page 9, lines 6 through 10, of her direct testimony, Staff witness Zichi provides that Staff is recommending adjustments to the Digital-Infrastructure Automation project due to lack of information from the Company supporting the prudency of this project and failure to quantify the operational cost reduction.

Q. Does the Company have a clarification of what was intended in this instance by "reducing operational costs" on page 98, lines 38 and 39 of my direct testimony?

A. Yes. The Company's use of "reducing operational costs" in this instance on page 98, lines 38 and 39, of my direct testimony was intended to state "avoiding operational costs"

due to the operational efficiencies through reducing manual processes and defects by automating tasks and doing more with less while improving quality and productivity. The operational efficiencies and avoided operational costs were discussed in several sections of the project synopsis, specifically the Objectives, page 99, lines 8 through 19 and Alternatives, page 99, line 25, through page 100, line 2, of my direct testimony. The risk mitigation and avoided costs were also provided in my Exhibit A-21 (SHB-6), pages 56 and 57, in the Corporate Risk and Other Value sections.

Q. Do you agree with Staff witness Zichi's proposed adjustments of the Digital-Infrastructure Automation project?

A. No. The Company does not agree with Staff witness Zichi's proposal of adjustments to the Digital-Infrastructure Automation project. The Digital-Infrastructure Automation project will reduce the risk of a major application failure due to security issues that arise in the infrastructure; optimize the deployment of infrastructure by reducing manual effort by 80%; and materially reduce misconfigurations, rework, and time to deliver deployment of infrastructure from 2-4 weeks to 1-3 days.

Q. What adjustments is Staff witness Zichi proposing for the ISIS Papyrus 2026 Upgrade project in this case?

A. On page 10, lines 11 through 21, of her direct testimony, Staff witness Zichi is proposing a full disallowance for the ISIS Papyrus 2026 Upgrade project.

Q. What amount is Staff witness Zichi proposing to adjust for the ISIS Papyrus 2026 Upgrade project?

A. Based on Staff witness Zichi's Exhibit S-14.0, line 9, she is proposing $164,499 in the projected 4-month bridge period ending 4/30/2026, and $263,199 (ROM Adjusted) for the

12-month test year ending 4/30/2027. This adjustment corresponds to the capital expenditures presented on Confidential Exhibit A-20 (SHB-5), line 228 and is within the IT/Digital Foundation business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5. Staff is also recommending a partial disallowance of $114,044 in Investments O&M expense for the 12-month test year ending 4/30/2027, which is under the Information Technology Investment O&M expense on Exhibit A-19 (SHB-3), page 1, line 3, and corresponds to the O&M expenses shown on Confidential Exhibit A-20 (SHB-5), line 228.

Q. What is Staff witness Zichi's rationale for proposing adjustments to the ISIS Papyrus 2026 Upgrade project?

A. On page 10, line 22 through page 11, line 18, of her direct testimony, Staff witness Zichi provides that Staff is recommending this adjustment due to a lack of information from the Company supporting the prudency of this project at this time.

Q. Do you agree with Staff witness Zichi's proposal of full disallowance of the ISIS Papyrus 2026 Upgrade project?

A. No. The Company does not agree that the upgrade is not required to be completed in 2026. The Company plans to implement the ISIS Papyrus upgrade in 2026 to mitigate the risk of technology obsolescence. Maintaining a current software release ensures the application receives critical security patches, vendor-issued fixes, and functional enhancements. The vendor has indicated they will continue providing cybersecurity patches. However, these patches may only apply to future releases. Cybersecurity patches of this nature cannot always be applied to older versions of the software. As a result, the Company may be required to upgrade to a more recent version to apply certain patches, depending on how

the vendor addresses specific vulnerabilities within the application code. The application has not been updated in over two years, delaying the upgrade increases the risk of technical obsolescence and exposure to security vulnerabilities, which will negatively impact the Company's ability to create electronic and paper bills, dunning notices, and customer correspondences.

Q. If Staff witness Zichi's proposed disallowance for the ISIS Papyrus 2026 Upgrade project is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?

A. Yes. The Company has identified necessary adjustments for the ISIS Papyrus 2026 Upgrade project. As stated on page 49 of my direct testimony, the Company's total capital projections include a 20% reduction for those projects with an ROM estimate. Based on the "ROM estimate type" indicated for the projects, which are shown in my Confidential Exhibit A-20 (SHB-5), column (k), the capital projections include reductions in the specified year. The projected 4-month bridge period ending 4/30/2026 capital expenditures for the ISIS Papyrus 2026 Upgrade project included in this case is the ROM-adjusted amount of $131,600 ($164,499 less 20% ROM Adjustment). Therefore, the ROM adjusted electric projected capital expenditures of $131,600 should be used for the 4-month bridge period ending 4/30/2026 rather than the $164,499 that Staff witness Zichi used for this period.

Q. Are there any other corrections the Company has identified for the ISIS Papyrus 2026 Upgrade project?

A. Yes. Based on Staff witness Zichi's Exhibit S-14.0, line 9, she is proposing disallowance of $114,044 in Investments O&M expense for the 12-month test year ending 4/30/2027.

By contrast, on page 10, lines 11 and 18, of her direct testimony, she is recommending partial disallowance of $144,044 in Investments O&M expense for the 12-month test year ending 4/30/2027. Based on the Investments O&M expense of $171,066 the Company provided on Confidential Exhibit A-20 (SHB-5), line 228, column (s), the correct Investments O&M expense amount for the 12-month test year ending 4/30/2027 is $114,044 (eight months of $171,066) as provided in Staff witness Zichi's Exhibit S-14.0, line 9.

Q. What adjustments is Staff witness Zichi proposing for the Security business category in this case?

A. On page 12, line 3, through page 14, line 8, of her direct testimony, Staff witness Zichi is proposing full disallowance of the Business Continuity – Program Management Tool project.

Q. What amount is Staff witness Zichi proposing to adjust for the Business Continuity-Program Management Tool project in this case.

A. Based on Staff witness Zichi's Exhibit S-14.0, line 11, she is proposing $50,579 in investments O&M expenses for the 12-month test year ending 4/30/2027. This adjustment corresponds to the investments O&M expenditure presented on Confidential Exhibit A-20 (SHB-5), lines 249 and 325, and is within Security business category on Exhibit A-19 (SHB-3), page 1, line 4.

Q. What is Staff witness Zichi's rationale for proposing full disallowance of the Business Continuity-Program Management Tool project?

A. On page 12, line 15, through page 13, line 11, of her direct testimony, Staff witness Zichi provides that new information was learned through audit regarding past decisions by the

Company for this project. Specifically, Staff learned that the Company adopted the Federal Emergency Management Administrative ("FEMA") and Incident Command System ("ICS") standards in 2013 and that the current system implemented in 2023 did not adhere to these standards. She concludes that the Company's current system should have adhered to these standards and further provides that the Company failed to address this inconsistency and provide supporting information as to the prudency of adopting these standards now.

Q. Do you agree with Staff witness Zichi's proposal of full disallowance of the Business Continuity – Program Management Tool project?

A. No. The Company does not agree with Staff's conclusion that the current system, implemented in 2023, should have included incident command system capabilities solely because the standards were adopted in 2013. The current tool supports Business Continuity ("BC") and Disaster Recovery ("DR") but does not include incident response capabilities aligned with FEMA and National Incident Management System ("NIMS") ICS principles. Incident management and BC/DR tools typically serve distinctly different functions. BC/DR tools focus on maintaining and restoring business functions during and after disruptions, while incident management tools address immediate response coordination and command during emergencies. The Company does not have an incident management tool in place. This was also true in 2023 at the time of procurement, although the Company had a BC/DR tool that was at risk of technology obsolescence. Thus, the chosen solution was selected to replace unsupported BC/DR software, fulfilling those immediate BC/DR requirements but not incident management needs. There is currently no single solution that comprehensively meets both BC/DR and FEMA/NIMS ICS-aligned incident management

requirements and that is cost effective, and the decision to procure the BC/DR solution was appropriate given the Company's needs and the capabilities available at the time.

Q. Did Staff provide any recommendations regarding the SAP S/4HANA Implementation project?

A. Yes. On page 14, line 16, through page 15, line 6, of her direct testimony, Staff witness Zichi proposed two recommendations regarding the SAP S/4HANA Implementation project.

First, Staff is recommending the Commission direct the Company to meet with Staff quarterly to provide progress of the SAP S/4HANA Implementation project, including any advancements and/or setbacks in project implementation, budget adherence, changes to project scope, timeline, expenses, and any problems the Company has experienced or anticipates experiencing with any operations or customer interactions.

Second, Staff is recommending the Company include in future rate case filings until implementation is complete, any over and under recovery of each projected expense for the project compared to the 80% base (ROM Adjusted Amount).

Q. Does the Company agree with Staff witness Zichi's recommendations regarding the SAP S/4HANA Implementation project?

A. Yes. The Company agrees with Staff witness Zichi's recommendations regarding the SAP S/4HANA Implementation project as described above.

Q. What projects is Staff witness Klocke proposing adjustments for in this case?

A. On page 4, lines 16 through 22, of her direct testimony, Staff witness Klocke is proposing adjustments for the Product Family Enhancement-Customer-Capital project that includes Customer Self-Service Mobile Application, Low Moderate Income ("LMI") Customer

Support, Web Chat AI, Web Dashboard Redesign, and Web Rebate for Personalization enhancements in Confidential Exhibit A-20 (SHB-5), lines 14, 112, 193, and 269. Company witness Jessica R. Byrom and I will address each proposed adjustment.

Q. What amounts is Staff witness Klocke proposing to disallow for the Product Family Enhancements-Customer-Capital project that includes Customer Self-Service Mobile Application, LMI Customer Support, Web Chat AI, Web Dashboard Redesign, and Web Rebate for Personalization enhancements?

A. Staff witness Klocke is proposing the following adjustments of the capital expenditures and IT Investments O&M expenses for the following enhancements that are a part of the Product Family Enhancements-Customer-Capital project based on Staff witness Klocke's Exhibit S-10.2, pages 1 through 2 and Staff witness Zichi's Exhibit S-14.0, line 1.

	Capital				O&M	
Enhancements	**Historical 12-Month Ended 12/31/2024**	**Bridge Period 12-Month Ending 12/31/2025**	**Bridge Period 4-Month Ended 4/30/2026**	**Test Year 12-Month Ended 4/30/2027**	**Projected Test Year**	**Exhibit S-10.2, page 1 Reference**
Customer Self-Service Mobile Application	$1,056,334	$1,305,671	$0	$0	$0	Lines 1 – 3, 5 – 11, and 14
LMI Customer Support	$0	$525,246	$0	$0	$0	Line 18
Web Chat Artificial Intelligence ("AI")	$0	$0	$157,574	$315,148	$19,896	Line 22
Web Dashboard Redesign		$525,246	$0	$0	$0	Line 17
Web Rebate Personalization	$0	$0	$87,541	$175,082	$11.053	Line 21
Total	$1,056,334	$2,356,163	$245.115	$490,230	$30,949	

Q. What adjustments is Staff witness Klocke proposing for Customer Self-Service Mobile Application enhancements that are part of the Product Family Enhancements-Customer-Capital project?

A. On page 5, lines 1 through 8, of her direct testimony, Staff witness Klocke is proposing an adjustment of $1,056,334 of capital expenditures for the historical year ended 12/31/2024 and $1,305,671 of capital expenditures for the year ending 12/31/2025 for the Customer Self-Service Mobile Application enhancements that are a part of the Product Family Enhancements-Customer-Capital project. This adjustment corresponds to the capital expenditures present on Confidential Exhibit A-20 (SHB-5), lines 14 and 112 and is within the Customer business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 2.

Q. Do you agree with Staff witness Klocke's adjustments to the Customer Self-Service Mobile Application enhancements that are a part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's adjustments of the Customer Self-Service Mobile Applications enhancements that are part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. What adjustment is Staff witness Klocke proposing for the LMI Customer Support enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. On page 7, lines 13 through 21, of her direct testimony, Staff witness Klocke is proposing a full disallowance of $525,246 in capital costs for the year ending 12/31/2025 for the LMI Customer Support enhancement that is a part of the Product Family Enhancements-

Customer-Capital project. This adjustment corresponds to the capital expenditures present on Confidential Exhibit A-20 (SHB-5), line 112 and is within the Customer business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 2.

Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the LMI enhancement that is part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the LMI enhancement that is a part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. What adjustments is Staff witness Klocke proposing for the Web Chat AI enhancement that is a part of the Product Family Enhancements-Customer-Capital in this case?

A. On page 14, lines 8 through 15, of her direct testimony, Staff witness Klocke is proposing full disallowance of $157,574 in capital expenditures for the partial bridge period ending 4/30/2026 and $315,148 in capital expenditures and $19,896 in Investments O&M for the partial test year ending 12/31/2026 for the Web Chat AI enhancement that is a part of the Product Family Enhancements-Customer-Capital project. This adjustment corresponds to the capital expenditures present on Confidential Exhibit A-20 (SHB-5), line 193 and is within the Customer business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 2.

Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the Web Chat AI enhancement that is part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the Web Chat AI enhancement that is part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. What adjustment is Staff witness Klocke proposing for the Web Dashboard Redesign enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. On page 16, lines 11 through 17, of her direct testimony, Staff witness Klocke is proposing disallowance of the $525,246 in capital expenditures for the bridge period ending 12/31/2025 for the Web Dashboard Redesign project that is a part of the Product Family Enhancements-Customer-Capital project. This adjustment corresponds to the capital expenditures present on Confidential Exhibit A-20 (SHB-5), lines 112 and is within the Customer business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 2.

Q. Do you agree with Staff witness Klocke's rationale for the adjustment of the Web Dashboard Redesign enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's rationale for the full disallowance of the Web Dashboard Redesign enhancement that is a part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. Do you agree with Staff witness Klocke's proposed adjustment of the Web Dashboard Redesign enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. Yes. Due to other higher priority work, the Web Dashboard Redesign enhancement will not be completed as planned. Therefore, the $525,246 in capital expenditures for the 12 months ending 12/31/2025 should be removed from this case.

Q. What adjustments is Staff witness Klocke proposing for the Web Rebate Personalization enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. On page 17, line 19, through page 18, line 3, of her direct testimony, Staff witness Klocke is proposing a full $87,541 for the partial bridge ending 4/30/2026 and $175,082 in capital expenditures and $16,580 in IT Investments O&M expense for the partial test year ending 12/31/2026 for the Web Rebate Personalization enhancement that is a part of the Product Family Enhancements-Customer-Capital project. This adjustment corresponds to the capital expenditures present on Confidential Exhibit A-20 (SHB-5), line 193 and is within the Customer business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 2.

Q. Do you agree with Staff witness Klocke's rationale for adjustment of the Web Rebate Personalization enhancement that is part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's rationale for full disallowance of the Web Rebate Personalization enhancement that is part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. Are there any other corrections the Company has identified to the IT Investments O&M expense for the Web Rebate Personalization enhancement that is part of the Product Family Enhancements-Customer-Capital project?

A. Yes. On page 18, lines 2 through 3, of Staff witness Klocke's direct testimony, she is proposing a disallowance of $16,580 in IT Investments O&M expense for the partial test year ending 12/31/2026. The correct partial test year ending 12/31/2026 amount is $11,053 (8 months of $16,580).

Q. Do you agree with Staff witness Klocke's proposed adjustment of the Web Rebate Personalization enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. Yes. Due to other higher priority work, the Web Rebate Personalization enhancement will not be completed as planned. Therefore, $87,541 for the partial bridge ending 4/30/2026 and $175,082 in capital expenditures and $11,053 in IT Investments O&M expense for the partial test year ending 12/31/2026.

Q. What is the current status of the Company's website redesign project Staff witness Klocke discusses in her direct testimony related to Web Chat AI, Customer Self-Service Mobile Application, and LMI Customer Support enhancements that are part of Product Family Enhancements-Customer-Capital project?

A. As discussed in Staff Audit Response U21870-SA-CE-080 (Exhibit A-186 (SHB-15)), the Company has put the website redesign on hold due to extended support of the current on-premises Sitecore web content management system and the Company's SAP S/4HANA planned implementation.

The previous timing for the website redesign was developed with the expectation that the Company would need to migrate to the cloud/Software-as-a-Service ("SaaS") version of the Sitecore system based on Sitecore's published product support lifecycle at that time. This would have been a major reason to initiate the website redesign. Since then, Sitecore has extended mainstream support for the on-premises version 10.4 to December 31, 2027, giving the Company more flexibility in its migration schedule.

In addition, the Company's implementation of the SAP S/4HANA system will be a major undertaking, which will significantly impact the design of integration between the Company's website and SAP. The Company plans to complete the S/4HANA implementation before starting the website redesign.

It is important to note that improvements to the Company's website design, content, navigation, accessibility, and features are not static or stopped until the website redesign project is undertaken. The Company is regularly prioritizing and executing updates to web pages, content, and flows based on customer needs and challenges. An example of this is for the LMI Customer Support Enhancement. In fact, much of the investment in this enhancement is being achieved through updates to website design, content, features, and navigation, without the full re-architecture associated with the eventual website redesign project.

Q. Do you agree that the Company's website redesign would negate the need to make investments in Customer Self-Service Mobile Application and Web Chat AI?

A. No. The Website Redesign would not negate the need to make investments in the Customer Self-Service Mobile Application, Web Chat AI, or any other channels preferred by

customers for specific needs, as discussed in Company witness Byrom's rebuttal testimony.

Q. What adjustments is Staff witness Duell proposing for the Service Restoration AI project in this case?

A. On page 21, lines 19 through 22, and page 22, lines 8 through 11, of her direct testimony, Staff witness Duell is proposing a partial adjustment for the Service Restoration Artificial Intelligence project.

Q. What amount is Staff witness Duell adjustments for the Service Restoration AI project?

A. Staff witness Duell is proposing an adjustment of $31,082 for the partial bridge period ending 4/30/2026 and $56,805 for the test year ending 4/30/2027.

Q. Do you agree with Staff witness Duell's proposal of adjustment of the Service Restoration AI project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Discovery Request No. U21870-ST-CE-0269 (Exhibit S-18, page 4) that Non-Labor Other costs for both capital and O&M in 2026 and 2027 were inadvertently miscalculated. The capital expenditures should be reduced by $31,082 in the 12-month bridge period ending 12/31/2025 and $56,805 for the projected test year ending 4/30/2027 for the Service Restoration AI project.

Q. Are there any corrections the Company has identified for the Service Restoration AI project?

A. Yes. On page 21, line 16, of Staff witness Duell's direct testimony, she indicates that the projected capital expenditures for the bridge period are $1,370,000 for the Service

Restoration AI project. Based on the Company's response to Staff Discovery Request No. U21870-ST-CE-0269 (Exhibit S-18, page 4), the correct projected capital expenditures for the bridge period are $754,716 ($603,773 ROM Adjusted). Additionally, on page 22, line 5, of Staff witness Duell's direct testimony, she indicates that the projected capital expenditures for the test year are $6,123,000. Based on Staff Discovery Request No. U21870-ST-CE-0269 (Exhibit S-18, page 4), the correct projected capital expenditures for the test year are $165,505 ($132,404 ROM Adjusted).

ATTORNEY GENERAL

Q. What amount does Attorney General witness Coppola propose removing for four IT projects that are in the investment planning phase?

A. On page 89, line 16, through page 90, line 19 of his direct testimony, Attorney General witness Coppola proposes to remove $1,448,000 of capital expenditures for the projected bridge ending in 4/30/26, $3,067,000 of capital expenditures for the projected test year ending in 4/30/2027, and $1,260,000 of O&M expense for the projected test year ending 4/30/2027 for the four IT projects in the investment planning phase. This adjustment corresponds to the following capital expenditures and Investments O&M expense in capital and O&M in Confidential Exhibit A-20 (SHB-5) and Exhibit A-12 (SHB-4), Schedule B-5.1, page 1.

Project	Business Category	Confidential Exhibit A-20 (SHB-5) Reference	Exhibit A-12 (SHB-4), Schedule B-5.1, page 1 Reference
Electric Geographic Information System ("GIS") Design Platform Modernization	Electric	Lines 23, 123, 200, and 276	Line 3
Electric GIS Utility Network Transformation	Electric	Line 277	Line 3
Integrated Energy Management Platform Optimization	Electric	Line 279	Line 3
Service Restoration Artificial Intelligence	Electric	Lines 204 and 282	Line 3

Q. What is the rationale Attorney General witness Coppola describes for adjustments to these four IT projects?

A. On page 90, lines 5 through 13, of his direct testimony, Attorney General witness Coppola is basing his proposal on the Company's responses to Discovery Request No. U21870-AG-CE-0592 (Exhibit AG-27, pages 1 through 6) on whether a project is in the Investment Planning phase or the detailed requirements phase (*i.e.,* whether detailed requirements[1] have yet to be completed).

Q. Does the Company agree with Attorney General witness Coppola's proposal to remove these four IT projects in the investment planning phase?

A. No. Attorney General witness Coppola's proposal is a broad brush to reduce costs for IT projects without considering the value created by these projects, nor recognizing the

[1] Detailed requirements typically include detailed business objectives and requirements, performance and security requirements, stakeholder requirements, function and non-functional solution requirements, refined cost estimates, refined project plan, conducting a Request for Proposal and contract management.

requirement work completed to develop each business case, as described in my direct testimony on page 36, line 20 through page 37, line 3.

Q. Does the Company agree that significant requirements are not complete, and that IT projects in the Investment Planning phase should be disallowed?

A. No. These four IT projects should not be disallowed on the basis that they are in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is incomplete or lacking information. An IT business case was completed and approved for this project prior to consideration for inclusion in the Company's rate case, following the Company's business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and these five IT projects should be included and approved as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

Q. Has the Company provided the value of these IT projects?

A. Yes. The Company has detailed the description, scope and value of each project in my direct testimony, exhibits and workpapers, audit and discovery responses, and provided exact references for each IT project.

Q. Can you please summarize the value for each of these IT projects?

A. Yes. The project name and the Company witness that has summarized the value for the four IT projects is below, including other supporting information provided in my Exhibit A-21 (SHB-6). The intangible value such as avoided costs, safety, and quality of these

projects must be considered along with the hard savings to provide a true picture of the opportunity missed if these projects are not approved.

Project	Witness	Exhibit A-21 (SHB-6) References
Electric GIS Design Platform Modernization	M. Kelly	Pages 58 and 59
Electric GIS Utility Network Transformation	M. Kelly	Pages 62 and 63
Integrated Energy Management Platform Optimization	M. Metz	Pages 101 and 102
Service Restoration Artificial Intelligence	A. Snider	Page 144

Q. Has the Company taken measures to address the concerns of over recovery of IT projects?

A. Yes. In addition to the detailed efforts the Company takes to investigate, provide quality reviews and approvals for each business case, the Company has proactively taken a 20% ROM reduction in this case to address Commission concerns from Case No. U-20963 of over recovery for projects that have a ROM estimate. This is discussed further in my direct testimony on page 49, line 1, through page 50, line 7.

Q. What amount does Attorney General witness Coppola propose removing for an additional five IT projects that are in the investment planning phase?

A. On page 91, line 1, through page 92, line 7 of his direct testimony, Attorney General witness Coppola proposes to remove $6,283,000 for the projected bridge ending in 4/30/26 and $11,428,000 for the projected test year ending in 4/30/2027 of capital expenditures, and 1,876,000 for the projected test year ending 4/30/2027 of Investments O&M expense for an additional five IT projects in the Investment Planning phase. This adjustment corresponds to the following capital expenditures and Investments O&M expense in Confidential Exhibit A-20 (SHB-5) and Exhibit A-12 (SHB-4), Schedule B-5.1, page 1.

Project	Business Category	Confidential Exhibit A-20 (SHB-5) References	Exhibit A-12 (SHB-4), Schedule B-5.1, page 1 References
Critical Substation Upgrade	Security	Lines 242 and 320	Line 6
Data & Analytics Platform Rationalization	IT/Digital Foundation	Lines 154 and 226	Line 5
Operational Technology (OT) Datacenter Migration	IT/Digital Foundation	Lines 222 and 302	Line 5
Forward Web Proxy Services	Security	Lines 252 and 328	Line 6
Physical Access Management and Alarm Response	Security	Lines 253 and 329	Line 6

Q. What is the rationale Attorney General witness Coppola describes for adjustments to these additional five IT projects?

A. On page 91, lines 9 through 17, of his direct testimony, Attorney General witness Coppola is basing his proposal on the Company's responses to Discovery Request Nos. U21870-AG-CE-0594, U21870-AG-CE-0595, U21870-AG-CE-0596, U21870-AG-CE-0601, and U21870-AG-CE-0602 (Exhibit AG-29, pages 1 through 12) on whether a project is in the Investment Planning phase and detailed requirements have yet to be completed.

Q. Does the Company agree with Attorney General witness Coppola's proposal to remove these additional five IT projects in the investment planning phase?

A. No. Attorney General witness Coppola's proposal is a broad brush to reduce costs for IT projects without considering the value created by these projects, nor recognizing the requirement work completed to develop each business case.

Q. Does the Company agree that significant requirements are not complete, and that IT projects in the Investment Planning phase should be disallowed?

A. No. These additional five IT projects should not be disallowed on the basis that they are in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is incomplete or lacking information. An IT business case was completed and approved for this project prior to consideration for inclusion in the Company's rate case, following the Company's business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and these five IT projects should be included and approved as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

Q. Has the Company provided the value of these IT projects?

A. Yes, the Company has detailed the description, scope and value of each project in my direct testimony, exhibits and workpapers, audit and discovery responses, and provided exact references for each IT project.

Q. Can you please summarize the value for each of these IT projects?

A. Yes. The project name and summarized value for each IT project is below, including the direct testimony cross reference and other supporting information provided in my Exhibit A-21 (SHB-6). The intangible value such as avoided costs, safety, and quality of these projects must be considered along with the hard savings to provide a true picture of the opportunity missed if these projects are not approved.

- Critical Substation Upgrade will provide enhanced perimeter and electronic security at designated substations to detect, deter, and respond to threats in real-time, thereby reducing the risk of large-scale outages, preserving electric delivery reliability, strengthening operational resilience, and protecting public safety and critical infrastructure. (Company witness Baker direct testimony page 79, line 13 through page 80, line 33 and Exhibit A-21 (SHB-6), pages 47 and 48.)

- Data & Analytics Platform Rationalization will consolidate outdated, inefficient legacy data and analytics systems into Data Lake 2.0, migrate reports to modern visualization tools, and retire duplicative legacy platforms to reduce total cost of ownership, eliminate redundant support and licensing burdens, improve data accessibility and governance, and enable scalable, cloud-aligned analytics capabilities. (Company witness Baker direct testimony page 97, line 4 through page 98, line 32 and Exhibit A-21 (SHB-6), page 51.)

- Operational Technology ("OT") Datacenter Migration will relocate critical OT infrastructure from the Parnall facility to a co-located vendor datacenter to eliminate site and environmental risks, ensure redundant power and climate controls, strengthen physical security and operational resilience, revalidate production and disaster-recovery procedures, and decommission an at-risk facility. (Company witness Baker direct testimony page 100, lines 3 through 40 and Exhibit A-21 (SHB-6), pages 114 and 115.)

- Forward Web Proxy Services will replace the current web proxy platform with a mature, scalable service to restore consistent access to internet and cloud resources, enforce advanced threat protections such as browser isolation and sandboxing, and implement continuous Zero Trust verification to preserve business continuity and reduce cyber risk. (Company witness Baker direct testimony page 114, line 30 through page 115, line 37 and Exhibit A-21 (SHB-6), pages 88 and 89.)

- Physical Access Management and Alarm Response will centralize physical access control to eliminate system instability, reduce manual intervention and rework, mitigate unauthorized access risk, enable mobile digital IDs, and improve alarm orchestration and compliance. (Company witness Baker direct testimony page115, line 38 through page117, line 24 and Exhibit A-21 (SHB-6), pages 116 and 117.)

This is a snapshot reminder of the benefits of these five IT projects that need to be considered when evaluating each project. The value of these projects should not be dismissed in a simple review of whether a project is in the Investment Planning phase.

Q. Has the Company taken measures to address the concerns of over recovery of IT projects?

A. Yes. In addition to the detailed efforts the Company takes to investigate, provide quality reviews and approvals for each business case, the Company has proactively taken a 20% ROM reduction in this case to address Commission concerns from Case No. U-20963 of over recovery for projects that have a ROM estimate. This is discussed further in my direct testimony on page 49, line 1, through page 50, line 7.

Q. Are there additional points that the Company would like to address for the additional five projects?

A. Yes. The Company would like to address additional points for the Critical Substation Upgrade, Data & Analytics Platform Rationalization, and OT Datacenter Migration projects.

Q. Are there any corrections the Company has identified for the Critical Substation Upgrade project?

A. Yes. Based projected test year capital of $3,498,167 for the Critical Substation Upgrade project provided in my direct testimony, on page 79, line 13, the correct projected ROM Adjusted Capital for the test year should be $2,798,533 ($3,498,167 less 20% ROM Adjustment) instead of the $3,135,966 amount I included in in my direct testimony, on page 79, line 14.

Q. If Attorney General witness Coppola's proposed disallowance for the Critical Substation Upgrade project is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?

A. Yes. The Company has identified necessary adjustments for the Critical Substation Upgrade project. Based on the corrected projected ROM Adjusted Capital previously provided in my rebuttal testimony for the test year of $2,798,533, the projected test year amount in Exhibit AG-28, line 6, for the Critical Substation Upgrade project should be updated to $2,798,533. Therefore, Attorney General witness Coppola's proposal to remove $11,428,000 in capital expenditures for the projected test year ending in 4/30/2027 should be updated to $11,091,000.

Q. Have any of the projects advanced beyond the Investment Planning phase?

A. Yes, the Data & Analytics Platform Rationalization project has completed the Planning phase and is now in Execute, with plans for the first release to go live in December 2025.

Q. What was the Commission's decision on page 130 of its September 30, 2025 Order in Case No. U-21806 related to the OT Datacenter Migration project?

A. The Commission found the Company provided insufficient justification on why relocating the datacenter to an entirely new facility is a cost-effective and reasonable option in comparison to fixing the problems in the existing building for the OT Datacenter Migration project. The Commission adopted the ALJ's recommendation, on pages 168-169 of the PFD in Case No. U-21806. Additionally, both the Commission and PFD indicated that this

project could be shown to be reasonable and prudent, should the Company provide more robust support for cost recovery.

Q. Has the Company estimated the costs of addressing the aging climate control equipment and continuing water filtration issues of the location of the datacenter in the basement of the Parnall building?

A. Yes. The Company has estimated the costs of addressing the aging climate control equipment and continuing water filtration issues of the current location to be $5,082,728. The projected costs to replace the aging climate control equipment including labor is $4,965,728. To remediate the water infiltration issue it would require removal of architectural concrete and replacing the waterproof membrane, which is estimated to be $117,000. This does not address the risk of the datacenter location being in the basement of the Parnall building near the main water pipe for the building. By moving the data center to a new co-located facility, this cost would be avoided and mitigate the risk of the location of the datacenter being near the main water pipe for the building.

Q. Why does the presence of a railway in the vicinity of the Parnall building make it an inappropriate site for a data center?

A. The presence of a railway near a data center increases physical risk such as vibration and environmental hazards such as trains carrying hazardous material or fuels. A more recent Industry standard, ANSI/BICSI 002-2024, recommends maintaining a safe distance – typically 1.6 km (1 mi) or more – to ensure long-term stability and minimize risk. The current distance from the railway to the building, where the data center is located, is approximately 170 meters.

Q. If the OT Datacenter Migration project were approved, would the Company be able to avoid costs in the ARP-OT Support Common and ARP-OT Support Electric projects in future years?

A. Yes. If the OT Datacenter Migration project were approved, the Company would be able to avoid ARP-OT Support Common and ARP-OT Support Electric project costs in future years.

Project	Total Company		Electric Allocation	
	Capital	O&M	Capital	O&M
ARP-OT Support Common	$809,200	$83,440	$554,868	$51,717
ARP-OT Support Electric	$828,600	$87,120	$828,600	$87,120

Q. In the Commission's September 30, 2025 Order in Case No. U-21806, pages 106-107, did the Commission advise the Company to refrain from submitting information confidentially that will directly affect the calculation of the revenue deficiency?

A. Yes. The Commission did advise the Company to refrain from submitting information confidentially that will directly affect the calculation of the revenue deficiency or, if the Company believes it is necessary to do so, to at least provide a detailed explanation of the reason for confidential treatment on the record.

Q. Why did the Company classify the capital expenditures and O&M expense amounts related to the SAP S/4HANA Implementation project as confidential?

A. The Company classified the capital expenditures and O&M expense amount related to the SAP S/4HANA Implementation project as confidential due to the impact of publicly disclosing the total projected costs of the project. Publicly disclosing the total projected project costs would impact the Company's ability to competitively bid contractor and software costs, impacting the cost-effectiveness of the project for customers.

Q. Does the Company intend to maintain the confidentiality of its test year capital expenditures and O&M expense and cloud implementation costs?

A. No. Given the Commissions advisement, the Company has decided to declassify the following items it previously classified as confidential:

- Company witness Baker Direct Testimony, page 102, amounts on lines 23 through 24;
- Company witness Daly Direct Testimony, page 33, amounts on lines 3, 4 and 9;
- Exhibit A-26 (SHB-11), line 1, column O; and
- Exhibit A-86 (PDD-62).

The Company is maintaining the confidential classification for the following items:

- Company witness Baker Direct Testimony, page 103, content on line 21;
- Confidential Exhibit A-20 (SHB-5), lines 162, 234, and 313, columns (e), (i), (j), (l) through (y); and
- Exhibit A-21 (SHB-6), page 137
- Exhibit A-26 (SHB-11), line 1, columns b through n.

For the declassified material, the Company plans to move to bind it into the record or admit it into evidence in the public record.

Q. What projected capital expenditures adjustments is Attorney General witness Coppola proposing for the SAP S/4HANA Implementation project identified on page 90 of his direct testimony?

A. Attorney General witness Coppola is proposing on page 95, lines 15 through 17, of his direct testimony to remove $20,392,000 for the 16 months ending April 2026 and

$34,793,000 for the projected test year of the Company's capital expenditures for the SAP S/4HANA Implementation project.

Q. What is Attorney General witness Coppola proposing for SAP S/4HANA Implementation project O&M costs identified on page 95 of his direct testimony?

A. Attorney General witness Coppola is proposing on page 95, line 17, through page 96, line 2, of his direct testimony to remove $15,178,000 O&M expense for the projected test year for the SAP S/4HANA Implementation project. Additionally, Attorney General witness Coppola proposes that the Commission reject the Company's proposal to defer $15,178,000 O&M costs into a regulatory asset.

Q. What is the argument Attorney General witness Coppola describes for capital expenditures adjustments and rejecting the proposal for deferral of O&M costs to a regulatory asset for the SAP S/4HANA Implementation project?

A. The first argument Attorney General witness Coppola describes on page 95, lines 7 through 10, of his direct testimony for removing capital amounts and rejecting deferral of O&M costs for the SAP S/4HANA Implementation project is his claim that the current Enterprise Resource Planning ("ERP") system still functions well and meets the Company's operating needs, and that it appears that the option exists for the Company to continue to operate the system into 2030 and potentially past the date with system support by SAP.

Q. Does the Company agree that the option exists to continue to operate the current system into 2030 and potentially past the date with system support by SAP?

A. No. The project will take approximately three years to complete and extended support for the Company's current SAP version is only available until 2030, as discussed in my direct testimony, on page 106, lines 12 through 19. There is also an increased risk of cyberattacks

if the SAP S/4HANA project is not executed because SAP has stated that after maintenance ends, standard patches will no longer be available, as discussed on page 106, line 20, through page 107, line 3, of my direct testimony.

Q. What is the second argument Attorney General witness Coppola describes for capital expenditure adjustments and rejecting the proposal for deferral of O&M costs to a regulatory asset for the SAP S/4HANA Implementation project?

A. The second argument Attorney General witness Coppola describes on page 95, lines 12 through 14, of his direct testimony for removing capital amounts and rejecting deferral of O&M costs for the SAP S/4HANA Implementation project is his contention that the project is premature.

Q. Does the Company agree the SAP S/4HANA Implementation project capital expenditures should be disallowed and proposal for deferral of O&M costs be rejected because it is premature and in the Investment Planning phase?

A. No. This project's capital expenditures should not be disallowed and proposal for deferral of O&M costs rejected on the basis that it is in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is premature or incomplete or lacking information. Although the Company issued a request for proposal in May 2025 for implementation partners, the Company leveraged a third party that specializes in preparing for S/4HANA upgrades to develop the cost estimates for the business case, as stated in my direct testimony on page 107, lines 14 through 16. The IT business case was completed and approved for this project prior to consideration for inclusion in the Company's rate case, following the same strict business case process. Even though the business case is complete and approved, projects remain in

this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and the project should be included and approved as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

Q. What is the argument Attorney General witness Coppola describes for removing the O&M amounts for the SAP S/4HANA Implementation project?

A. Similar to the capital expenditures, the argument Attorney General witness Coppola describes on page 95, lines 7 through 14, of his direct testimony for removing amounts for the SAP S/4HANA Implementation project is his contention that the project is premature.

Q. What was the Commission's decision on page 106 of its September 30, 2025 Order in Case No. U-21806 related to the SAP S/4HANA Implementation project?

A. The Commission found the Company's evidence to be satisfactory and adopted the ALJ's recommendation, on page 134 of the PFD in Case No. U-21806, to approve the SAP S/4HANA Implementation project and the associated requests for deferral of O&M expenses and amortization of the associated cloud computing costs and declined to disallow the project as recommended by the Attorney General.

Q. What adjustments is Attorney General witness Coppola proposing for the ARP-FDAM project in this case?

A. On page 97, lines 6 through 11, of his direct testimony, Attorney General witness Coppola is recommending a partial disallowance of $1,039,000 for the project bridge period ending 4/30/2026 and $2,513,000 for the project test year in capital expenditures for the ARP-FDAM project.

Q. Do you agree with Attorney General witness Coppola's proposal, at page 97, of his direct testimony, to reduce capital expenditures for the 16 months ending April 2026 by $1,039,000, and for the projected test year to $2,513,000 for the ARP-FDAM project?

A. No. Attorney General witness Coppola is basing the projections on a three-year historical average plus an adjustment for forecasted inflation. This does not consider that the cost projected for each year for the ARP-FDAM project is for specific hardware that requires replacement based on timing of when it was installed and risk if it were not replaced in the four-year refresh cycle.

Q. What other evidence should Attorney General witness Coppola consider when evaluating the prudency and reasonableness of the projected test year capital expenditures for the ARP-FDAM in addition to the actual capital expenditures provided in Discovery Response No. U21870-AG-CE-0603 (Exhibit AG-31)?

A. Attorney General witness Coppola should consider the following other evidence: (1) the new field device purchases that were purchased as a part of the ARP-WAM project in 2021, 2022, and 2023; and (2) the 425 new field device that were purchased in 2022 for training and the Compression Digital Mobility project, as discussed in my direct testimony, page 67, lines 6 through 9.

In Staff Audit Response U21870-SA-CE-008 (Exhibit S-14.1), the Company provided the new field device purchases that were purchased under the ARP-WAM project in 2021, 2022, and 2023. Additionally, the Company provided further information on the 425 new field devices purchased in 2022 discussed in my direct testimony on page 67, lines 6 through 9, in Staff Audit Responses U21870-SA-CE-024 and U21870-SA-CE-090

(Exhibit A-184 (SHB-13). These field devices are now planned to be refreshed as a part of the ARP-FDAM project in 2026.

Q. Please describe Exhibit A-185 (SHB-14).

A. Exhibit A-185 (SHB-14) is the number of replacements and new purchases for 2021, 2022, 2023, and 2024 for the ARP-FDAM project, aggregating the data provided in Staff Audit Response U21870-SA-CE-008 (Exhibit S-14.1), Discovery Response U21870-AG-CE-0603 (Exhibit AG-31), and Staff Audit Responses U21870-SA-CE-024 and U21870-SA-CE-090 (Exhibit A-184 (SHB-13). Specifically:

- Column (a) provides the unit description;
- Column (b) provides the average unit cost;
- Column (c) provides the total number of units for the specified year;
- Column (d) provides total actual capital expenditures for the specified year;
- Column (g) provides the total actual electric allocation of capital expenditures for the specified year; and
- Column (h) provides a reference for the actual data.

Q. What is the impact of co-workers not having a field device to perform work in service of customers?

A. The absence of field devices for co-workers can significantly impact their ability to perform work effectively. Without field devices, co-workers face productivity losses due to the need to access information through less efficient means, such as using paper-based resources. This can lead to delays in work initiation and completion. The lack of access to electronic safety manuals and resources can increase safety risks. Workers may not have the most up-to-date safety information readily available, which is crucial for maintaining a safe working environment. Field devices facilitate better communication, especially

during emergencies or unexpected events. Without them, there is a risk of losing business continuity and effective communication, which can hinder timely responses to customer needs. Field devices provide access to online training and Company resources, which are essential for continuous learning and skill development. Without these devices, workers may miss out on training, leading to a gap in knowledge and skills. Sharing devices among employees can pose cybersecurity risks. Field devices help mitigate these risks by providing individual access to necessary resources, reducing the need for device sharing. Overall, the lack of field devices can lead to decreased efficiency, increased safety risks, and hindered communication, all of which negatively impact the service provided to customers.

Q. If Attorney General witness Coppola's proposed disallowance for the ARP-FDAM project is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?

A. Yes. The Company has identified necessary adjustments for the ARP-FDAM project. Referring to page 97, lines 1 through 6, of Attorney General witness Coppola's direct testimony, the calculation of the forecasted capital expenditures of $2,957.000 is not correct. Based on the most recent three historical years from 2022 to 2024 of $2,218,000, then prorated to 16 months and applying the inflation factor of 2.9%, the forecasted capital expenditures would be $3,043,000 ($2,218,00 X 16/12 X 1.029). Therefore, the adjustment would be $953,000 rather than $1,039,000.

Q. If Attorney General witness Coppola's proposed disallowance for the ARP-FDAM project is nonetheless adopted, is there overlap with Staff witness Zichi's proposed disallowance for the same project?

A. Yes. If Attorney General witness Coppola's proposal that ARP-FDAM should be projected based on a three-year average plus inflation, which it should not, the resulting disallowance should be offset by the amounts reduced by the Company, as discussed in response to Staff witness Zichi above, related to new field device purchases of $24,696 for the 4-month bridge period ending 4/30/2026 and $74,089 for the projected test year ending 4/30/2027 of capital expenditures, Additionally, Attorney General witness Coppola's proposal should be offset if Staff witness Zichi's proposal for a full disallowance of $228,567 for the 4-month bridge period ending 4/30/2026 and $658,700 for the projected test year ending 4/30/2027 of capital expenditures for new field devices is adopted.

Q. Does this conclude your rebuttal testimony

A. Yes.

MR. GENSCH: Thank you, Your Honor.

Next is the direct testimony of Marc R. Bleckman, consisting of a cover page and 55 pages of questions and answers. Mr. Bleckman also had rebuttal testimony consisting of a cover page and 70 pages of questions and answers. Mr. Bleckman also had a number of exhibits including Exhibit A-14 with Schedules D-1, D-1A, B, D-2, D-3, D-4, and D-6, and another witness will sponsor schedule D-5 to that exhibit. He also had Exhibits A-27 through A-40 and exhibits A-187 through A-190.

THE COURT: All right. Mr. Gensch, I don't know if you were on when I discussed with Ms. Uitvlugt about the admission of exhibits that have various schedules that are incomplete. We're going to wait until the entirety of the schedules for any given exhibit are being proposed for admission to have the underlying exhibit admitted. So with that said is, are there any objections to the admission of the testimony in exhibit sponsored by Mr. Bleckman?

Hearing none. The direct and rebuttal testimony of Marc Bleckman is bound on the record, and Exhibits A-27 through A-40, and exhibits A-187 through A-190 are admitted.

(At 2:41 p.m., Exhibits A-27 through A-40 and Exhibits A-187 through A-190 admitted).

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Marc R. Bleckman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Financial Planning and Analysis.

Q. What are your current responsibilities?

A. My responsibilities include preparation of the monthly forecasts, annual budgets, and long-term financial plans for Consumers Energy and CMS Energy, the parent company of Consumers Energy. As a part of my role, I conduct financial analyses and studies required for making various strategic decisions such as equity issuance, sale of businesses, and new investments. I assist the Chief Financial Officer in preparing the presentations for Board of Directors meetings, quarterly earnings calls, investor meetings, and industry conferences. My responsibilities also include preparation of the Renewable Energy Plan ("RE Plan") forecast model, which is a responsibility I have continued to assume from a previously held position.

Q. Please describe your educational background and describe any positions held prior to your current position.

A. I received a Master of Business Administration Degree with a Finance concentration from the Katz Graduate School at the University of Pittsburgh in 2002. Upon receiving this degree in May 2002, I joined Ford Motor Company ("Ford") as a Financial Analyst. During my seven years of employment at Ford, I worked in various finance roles throughout the company, including Assembly Operations, Powertrain Operations, Ford

Motor Credit, and the General Auditor's Office. My responsibilities within these organizations included, but were not limited to, forecasting of and variance reporting on, all Income Statement and Balance Sheet line items, as well as business process auditing. In July 2009, I left Ford to join Consumers Energy as a Principal Financial Analyst in the Company's Risk, Strategy, and Financial Advisory Services group. My responsibilities in this role included, but were not limited to, supporting the financial analysis and forecasting of the Company's renewable energy development plans, as well as conducting the Company's Enterprise Risk Management Program. In September 2012, I took on the role of Manager of Earnings Analysis in the Company's Financial Planning and Analysis Group. I assumed my current position as the Executive Director of Financial Planning and Analysis in February 2016.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in:

- Case No. U-16543, the Company's 2011 Application to Amend the RE Plan;
- Case No. U-16581, the Company's 2011 Application for biennial review of the RE Plan;
- Case No. U-17301, the Company's 2013 Application for biennial review of the RE Plan;
- Case No. U-17752, the Company's 2015 Application to Amend the RE Plan;
- Case No. U-17792, the Company's 2015 Application for biennial review of the RE Plan;
- Case No. U-18231, the Company's 2017 Application for biennial review of the RE Plan;
- Case No. U-20322, the Company's 2018 Gas Rate Case;
- Case No. U-20483, the Company's RE Plan reconciliation proceeding for 2018;

- Case No. U-20650, the Company's 2019 Gas Rate Case;
- Case No. U-20697, the Company's 2020 Electric Rate Case;
- Case No. U-20722, the Company's RE Plan reconciliation proceeding for 2019;
- Case No. U-20963, the Company's 2021 Electric Rate Case;
- Case No. U-20984, the Company's RE Plan amendment proceeding for 2021;
- Case No. U-21009, the Company's RE Plan reconciliation proceeding for 2020;
- Case No. U-21148, the Company's 2021 Gas Rate Case;
- Case No. U-21197, the Company's RE Plan reconciliation proceeding for 2021;
- Case No. U-21224, the Company's 2022 Electric Rate Case;
- Case No. U-21308, the Company's 2022 Gas Rate Case;
- Case No. U-21352, the Company's RE Plan reconciliation proceeding for 2022;
- Case No. U-21374, the Company's Application for approval of revised Voluntary Green Pricing programs and a RE Plan amendment;
- Case No. U-21389, the Company's 2023 Electric Rate Case;
- Case No. U-21490, the Company's 2023 Gas Rate Case;
- Case No. U-21549, the Company's RE Plan reconciliation proceeding for 2023;
- Case No. U-21585, the Company's 2024 Electric Rate Case;
- Case No. U-21816, the Company's RE Plan amendment proceeding for 2024; and
- Case No. U-21806, the Company's 2024 Gas Rate Case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present my recommendations regarding the capital structure and cost of capital which should be used in computing the overall rate of return for Consumers Energy.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. SUMMARY OF RECOMMENDATIONS

II. CAPITAL STRUCTURE AND COST RATES

A. Development of Capital Structure

B. Development of Cost Rates

III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS AND RECENT UTILITY BOND ISSUANCES

IV. PROJECTED CASH BALANCE

V. SHORT-TERM BORROWING FACILITIES

VI. RENEWABLES LIABILITY

VII. LINE CLEARING PROGRAM RAMP-UP

VIII. SUMMARY AND CONCLUSIONS

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-14 (MRB-1)	Schedule D-1	Overall Rate of Return Summary;
Exhibit A-14 (MRB-2)	Schedule D-1a	Capital Structure Development;
Exhibit A-14 (MRB-3)	Schedule D-1b	Comparison of Development of Capital Structure;
Exhibit A-14 (MRB-4)	Schedule D-2	Cost of Long-Term Debt;
Exhibit A-14 (MRB-5)	Schedule D-3	Cost of Short-Term Debt;
Exhibit A-14 (MRB-6)	Schedule D-4	Cost of Preferred Stock;
Exhibit A-14 (MRB-7)	Schedule D-6	Short-Term Debt Utilization;
Exhibit A-27 (MRB-8)		Current and Historical Credit Ratings;

Exhibit A-28 (MRB-9)	Recent Utility Corporate Bond Issuances;
Exhibit A-29 (MRB-10)	Peer Company Commission Authorized Equity Ratios;
Exhibit A-30 (MRB-11)	State Regulatory Evaluations;
Exhibit A-31 (MRB-12)	Wells Fargo December 8, 2023 Report – Figure of the Week: Approved Equity Ratios, 2005-2023;
Exhibit A-32 (MRB-13)	Cumulative Annual Interest Savings;
Exhibit A-33 (MRB-14)	S&P Global August 7, 2024 Report – RRA State Regulatory Evaluations – Energy;
Exhibit A-34 (MRB-15)	UBS May 10, 2023 Report;
Exhibit A-35 (MRB-16)	S&P February 14, 2024 Report;
Exhibit A-36 (MRB-17)	S&P August 20, 2024 Credit Report;
Exhibit A-37 (MRB-18)	Moody's May 31, 2024 Credit Report;
Exhibit A-38 (MRB-19)	Fitch April 16, 2024 Credit Report;
Exhibit A-39 (MRB-20)	Peer Company Revolver Capacity Analysis; and
Exhibit A-40 (MRB-21)	S&P January 14, 2025 Report.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

I. SUMMARY OF RECOMMENDATIONS

Q. What capital structure are you recommending be utilized in the overall rate of return calculation?

A. I am recommending that the capital structure shown on page 1 of Exhibit A-14 (MRB-1), Schedule D-1, be used in this case. This represents the actual capital structure as of

December 31, 2024, adjusted for the projected changes in debt, equity, deferred income taxes, and Investment Tax Credit ("ITC") through the end of the test year ending on April 30, 2027. The development of the capital structure on a ratemaking basis is shown in columns (b) through (d). The equity ratio as a percentage of permanent capital is 50.75%. The equity ratio as a percentage of total capital is 42.94%.

Q. What Return on Equity ("ROE") are you assuming to determine the overall cost of capital for Consumers Energy?

A. I am assuming an ROE for Consumers Energy of 10.25%. This ROE is recommended by Company witness Ann E. Bulkley and supported in further detail in her direct testimony.

Q. What is the overall rate of return for Consumers Energy that you recommend be used in this case?

A. I am recommending an overall rate of return of 6.35% on an after-tax basis. This overall rate of return is the result of combining the capital structure and cost rates shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. The cost of the components and the weighted cost are shown in columns (e) through (i). The overall rate of return that I am recommending is the weighted cost of the various components of the capital structure.

II. CAPITAL STRUCTURE AND COST RATES

A. Development of Capital Structure

Q. What is capital structure?

A. Capital structure refers to the amounts and mix of a company's financing components which make up the funds used for its operations and capital investment. For the Company, this includes long-term debt, common equity, preferred equity (or preferred stock), short-term debt, ITC, and deferred income taxes.

Q. What is long-term debt and short-term debt?

A. Long-term debt consists of loans that have a due date (or maturity) that is more than one year from the date of issuance. For the Company, long-term debt consists exclusively of First Mortgage Bonds. Short-term debt represents borrowings that are short-term in nature (less than one year), and includes borrowings under the Company's credit facilities, including commercial paper and intercompany borrowings. The Company aims to finance its long-term capital (such as plant and property) with long-term debt and equity, and to finance short-term capital requirements (such as seasonal working capital needs) with short-term debt. This financing strategy is explained in more detail later in my direct testimony.

Q. What is common equity and preferred equity?

A. Equity is the net worth (assets minus liabilities) of a company. Common equity increases with net income (retained earnings) and with equity contributions from the Company's parent, CMS Energy. Common equity decreases when the Company makes dividend distributions to CMS Energy. Preferred equity is distinguished from common equity in that there is a fixed preferred dividend rate on preferred stock. Also, preferred equity has a higher ("preferred") claim to the Company's net assets in the event of insolvency.

Q. Do taxes play a part in the capital structure?

A. Yes. Deferred taxes and ITC represent reported book taxes that, due to special Internal Revenue Service deductions, measurements, or treatments, will not have to be paid until sometime in the future. This represents a temporary "zero cost" source of funding for the Company and is included as a component of the capital structure.

Q. How did you develop the long-term debt, preferred stock, common equity, short-term debt, deferred income tax, and ITC balances in the capital structure?

A. I started with the actual balances of long-term debt, preferred stock, common equity, short-term debt, deferred income taxes, and ITC as of December 31, 2024, as shown in Exhibit A-14 (MRB-2), Schedule D-1a, page 1, column (e). I then made the adjustments shown in column (f) to arrive at the average test year balance ending April 30, 2027, in column (g) that I am recommending be used in this case.

Q. Please explain the common equity adjustment of $2.511 billion.

A. I have projected that the 13-month common equity balance for the test year will be $2.511 billion higher than the December 31, 2024 balance. The common equity adjustment of $2.511 billion consists of two components. The first is an adjustment to reflect $369 million in projected retained earnings on a weighted average basis from January 2025 through April 2027. The second is an adjustment of $2.142 billion to reflect the projected equity infusions on a weighted average basis from January 2025 through April 2027.

Q. What are retained earnings?

A. Retained earnings are a company's net income from operations and other business activities retained by the company as additional equity capital. Retained earnings are, thus, a part of stockholders' equity.

Q. Please explain the retained earnings adjustment of $369 million.

A. Since I started with the December 31, 2024 balance for common equity, it was necessary to make an adjustment to reflect the increase in the common equity balance through retained earnings that will occur on a weighted average basis through April 30, 2027.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2025 through the test period ending April 2027.

A. Consumers Energy has a long-standing policy of using an 80% dividend payout ratio. I assumed Consumers Energy's retained earnings rate to be $16.783 million per month, or $201.4 million per year, from January 2025 through April 2027.

Q. Please explain how you arrived at Consumers Energy's retained earnings rate of $201.4 million per year.

A. Based on Consumers Energy's Securities and Exchange Commission Form 10-K for 2024, I determined that Consumers Energy's net income for the 12-month period ended December 31, 2024, was $1.007 billion. I used this amount as a proxy for the future net income and assumed a dividend payout ratio of 80%. Using these assumptions, I calculated an annual retained earnings amount of $201.4 million [$1,007 x (1-0.80)]. Exhibit A-14 (MRB-2), Schedule D-1a, page 3, shows the projected monthly retained earnings balance and calculates the 13-month average for the period ending April 30, 2027.

Q. What are equity infusions?

A. Equity infusions are cash investments made by CMS Energy into Consumers Energy, thereby increasing the Company's common equity balance.

Q. Why did you make a $2.142 billion adjustment for the new equity infusions in your recommended capital structure?

A. This is the amount needed to hold a 50.75% equity ratio for the test period in this case. CMS Energy made an equity infusion of $150 million in February 2025 and plans to make equity infusions of $275 million by May 2025, $425 million by June 2025, $40 million by October 2025, $525 million by February 2026, $675 million by June 2026, and

$675 million by February 2027. Accordingly, I reflected this in the equity balance for the test year for this case on a weighted average basis. The impact of these equity infusions on the cumulative balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 3. The 13-month average for the period ending April 30, 2027, is $2.142 billion. When the 13-month average for the equity infusions of $2.142 billion is combined with the 13-month average $369 million retained earnings adjustment, the increase to equity capital is the $2.511 billion shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 1.

Q. How is your testimony structured with regards to the proposed equity ratio?

A. My testimony describing the key factors and providing evidence that supports the proposed equity ratio of 50.75% is organized as follows:

i. Peer Authorized Equity Ratios are Higher and Trending Up

ii. Equity Ratio/ROE Impact on Credit Quality

iii. Rating Agencies' Assessment of the Regulatory Environment

iv. Credit Challenges Facing Regulated Utilities

i. Peer Authorized Equity Ratios are Higher and Trending Up

Q. How does the 50.75% equity ratio proposed in this case compare to other utilities?

A. To compare the 50.75% equity ratio proposed in this case to other utilities, I researched all rate case decisions of peer companies from 2020 through mid-April 2025 and determined the authorized or approved equity ratio for each. This is reflected on Exhibit A-29 (MRB-10). Peer companies for this analysis is defined as regulated subsidiaries of the Company's ROE proxy group reflected on Exhibit A-14 (AEB-1), Schedule D-5, page 2, and excludes orders received by in-state proxy DTE Energy Company as well as the

Company. The average equity ratio for the peer group was 51.85%, 110 basis points higher than the 50.75% proposed for Consumers Energy in this case.

Q. Are the equity ratios reflected in your sample based on reported financial data or Commission-authorized equity ratios in regulatory proceedings?

A. The equity ratios were taken from Commission orders and public filings and represent actual regulatory equity ratios authorized or approved by different commissions across the country. It is clear from this analysis that, on average, regulatory commissions of the Company's peer group are granting equity ratios that are much higher than the 50.75% that is proposed by the Company in the current case.

Q. Are the utilities included in Exhibit A-29 (MRB-10) companies at the parent holding company level or the regulated subsidiary level?

A. The utilities included in Exhibit A-29 (MRB-10) are at the regulated subsidiary level. This is important because Consumers Energy is a regulated subsidiary; therefore, the comparison to the average commission-authorized equity ratios also needs to be at that same level in order for the analysis to be a valid comparable benchmark in this case.

Q. Is it appropriate to use equity ratios at the parent holding company level in order to determine the average "peer group" equity ratio for the Company in this case?

A. No. Companies at the parent holding company level should not be considered "peers" for purposes of determining the average equity ratio for the Company's peer group. This would be a misleading comparison since equity ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items. In addition, an analysis of equity ratios at the parent holding company level may also be skewed since the source for this data is most likely Securities and Exchange Commission reported financial statements,

which are prepared under Generally Accepted Accounting Principles. There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis which would further distort the equity ratios calculated at the parent holding company level.

Q. Has the Commission addressed the fact that an analysis of equity ratios at the parent holding company level is not appropriate?

A. Yes. In its Order in Case No. U-20963, the Commission stated that "regulatory and financial data should not be combined" with such an analysis. Further, the Commission deemed that such an analysis is invalid assuming one "could not verify that its data contained equity ratios set by a regulatory commission in a rate case." It is clear from the Commission's Order that actual commission authorized equity ratios at the regulated subsidiary level as presented in Exhibit A-29 (MRB-10) is the preferred data source for an analysis comparing relative equity ratios of peers.

Q. How does the trend in the Company's authorized equity ratio compare to other utilities?

A. Equity ratios for regulated utilities have increased over the last several years. This trend was highlighted in a December 2023 Wells Fargo report on approved equity ratios. See Exhibit A-31 (MRB-12). As described in the Company's testimony in previous rate cases, negative cash flow and credit metric impacts occurred when federal tax changes took effect in 2018. In subsequent years, utility commissions adopted higher equity ratios as one way to combat those impacts. The Wells Fargo report shows an increase in approved electric utility equity ratios of 130 basis points from 2019 to 2023. In contrast, the Company's authorized equity ratio has <u>decreased</u> 205 basis points from 2019 (Case No. U-20322) to

present, weakening credit quality and putting the Company's credit rating at risk. The Company has presented data showing that peer authorized equity ratios are significantly higher and are trending up. While this data indicates that a higher equity ratio is warranted, the Company is proposing an equity ratio of 50.75% in this case. This is the minimum amount that, taken together with an ROE of 10.25%, reflects the appropriate level that the Commission should adopt to help preserve Consumers Energy's current credit rating.

ii. Equity Ratio / ROE Impact on Credit Quality

Q. How does the equity ratio approved in this case impact the Company's credit metrics and credit quality?

A. A key financial metric used by rating agencies is the ratio of Funds From Operations ("FFO") to Debt ("FFO-to-Debt ratio"). The calculation of this financial metric includes, in part, both the equity ratio and the authorized ROE of the Company; thus, there needs to be a balance between the Company's equity ratio and ROE that will ensure that this key financial metric does not degrade and cause significant credit deterioration. An equity ratio of 50.75% and an ROE of 10.25%, as recommended by the Company in this case, results in an FFO-to-Debt ratio that is sufficient in striking this balance.

Q. What is an FFO-to-Debt ratio?

A. An FFO-to-Debt ratio is a financial metric that compares a company's cash flow from operating activities to a company's leverage, or debt outstanding. It can also be described as a type of payback ratio, reflecting the Company's ability to repay its outstanding debt with operating cash flow. A higher FFO-to-Debt ratio, one which reflects a higher level of cash flow from operating activities to offset or otherwise reduce the risk associated with the Company's ability to pay its debts, is viewed favorably and indicative of a lower financial risk and a resulting higher relative credit rating. A higher credit rating, in turn,

results in lower financing rates. This is comparable to a bank's credit evaluation for someone requesting a personal loan. After reviewing personal income and outstanding debt, banks generally offer lower financing rates to individuals who have more cash flow to repay debt, indicating a relatively higher credit quality.

Q. Discuss the relationship between the Company's ROE, its equity ratio, and the Company's credit metrics.

A. As discussed earlier in my testimony, ROE and equity ratio are two inputs in determining the Company's ratio of FFO to Debt, and FFO-to-Debt ratios are used by credit agencies to determine the Company's financial health. Consequently, it is important to recognize that the Company's ROE and equity ratio cannot be evaluated in isolation, but should, instead, be viewed as interconnected components that determine the Company's overall financial health. An ROE of 10.25%, when taken <u>together</u> with an equity ratio of 50.75% results in an FFO-to-Debt ratio that the Company believes is acceptable in the current case and is responsive to recent Commission orders. A lower authorized ROE would, therefore, necessitate a higher approved equity ratio to maintain the same level of financial health.

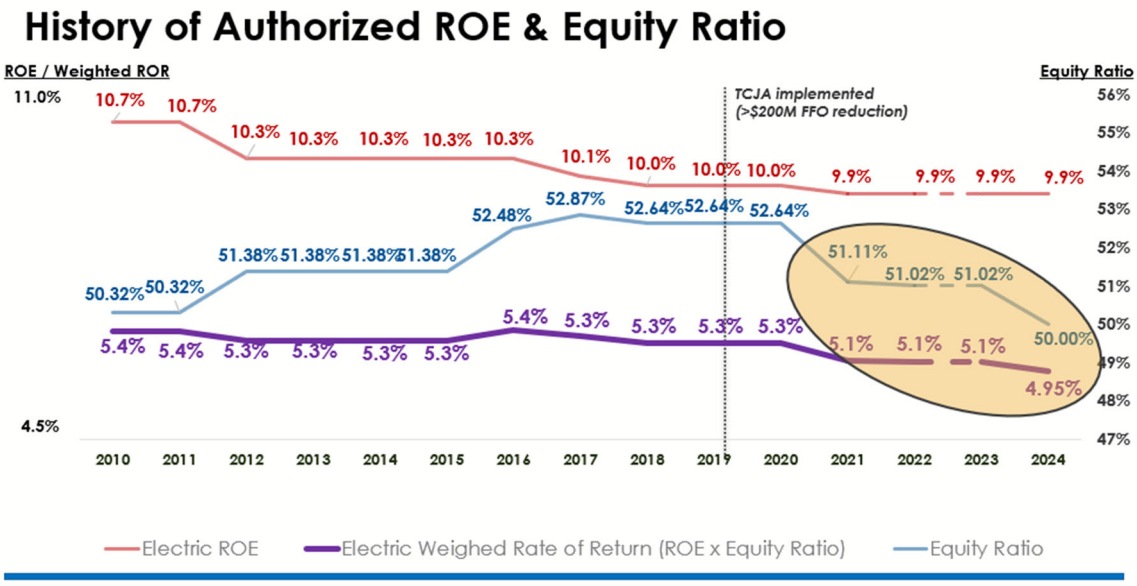
Q. How can the combined cost of a Company's equity ratio and ROE components be properly evaluated?

A. Multiplying the equity ratio by the ROE produces a weighted cost or "rate of return." This is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. On line 6 of this exhibit, the equity ratio of 50.75% from column (c) is multiplied by the ROE of 10.25% from column (e) to produce a weighted cost of 5.20%, shown in column (f). This is the weighted cost of common equity, a component of the Company's overall rate of return. This rate of return is important to consider since it takes into account the equity ratio in combination

with the ROE. As discussed earlier in my testimony, the 50.75% equity ratio and 10.25% ROE is a combination that the Company believes is acceptable in the current case.

Q. What has been the recent trend of the Company's weighted rate of return?

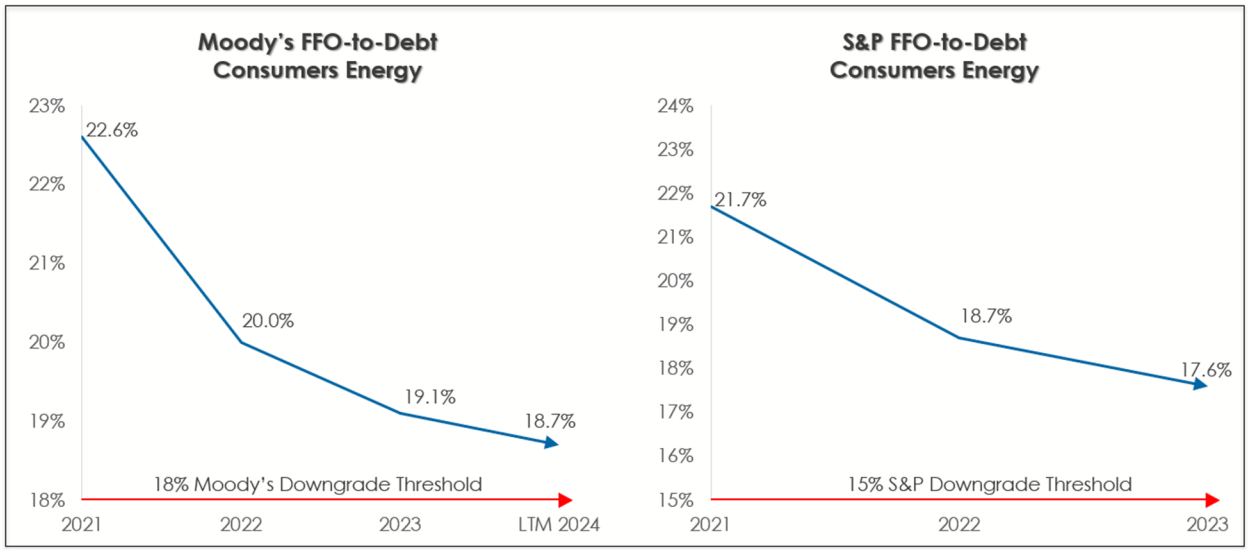
A. Following a long period of stability, recent rate cases have resulted in a sharp decline in rate of return. This is illustrated in the following chart which includes a history of electric authorized ROE, equity ratio, and resulting weighted rate of return.



Q. What has been the trend of the Company's credit metrics over the last few years?

A. The Company's FFO-to-Debt ratio as calculated by Standard and Poor's ("S&P") has been trending down in recent years from 21.7% in 2021 to 17.6% in 2023, a decrease of 410 basis points and, for 2023, 40 basis points below the low end of S&P's expected range outlined in its August 2023 report. In addition, the Company's FFO-to-Debt ratio as calculated by Moody's Investors Service ("Moody's") has also been trending down in recent years from 22.6% in 2021 to 19.1% in 2023, a decrease of 350 basis points. Moody's May 2024 credit report also shows a further decline to 18.7% for the 12 months ended March 2024. The Company's FFO-to-Debt ratio as calculated by Moody's is trending

down and was well below the low end of Moody's expected range (20-21%) for the Company for 2023 and through the first quarter of 2024. These credit metric results are shown in the following chart:



As explained earlier in my direct testimony, recent rate cases have resulted in a sharp decline in rate of return (ROE multiplied by equity ratio). A reduction in the Company's rate of return lowers the Company's cash flow and FFO-to-Debt ratio. The Company also needs to increase its long-term debt to achieve a lower equity ratio. This increase in debt also weakens the Company's FFO-to-Debt ratio. These negative credit metric impacts puts the Company's credit quality and credit ratings at risk.

Q. Are there any new circumstances that could have material impacts on the Company's credit metrics during the test year of this case?

A. Yes. A high degree of volatility and economic uncertainty has emerged in recent months with respect to financial markets, interest rates, and geopolitical tensions. The Trump administration, signaling a significant shift in American trade policy, has placed significantly higher tariffs on imported goods, causing a substantial impact on the U.S. economy. Companies reliant on global supply chains faced elevated input costs, which

translated into higher consumer prices and contributed to sustained inflationary pressures. In addition, the heightened trade tensions created an atmosphere of uncertainty that negatively affected business investment and led to heightened volatility in financial markets. An April 2025 Wall Street Journal article titled "Huge Stock Swings Are the New Normal for Frazzled Investors" stated that April 2025 is poised to be the most-volatile calendar month since the COVID crash in 2020. The VIX, a stock market index that measures investors' expectation of volatility, peaked at 52.33 on April 8, 2025. The VIX has not reached 50.00 since April 2020 during the height of the COVID-19 pandemic. Fears of a sharp economic downturn have also dramatically increased. In April 2025, J.P. Morgan Research raised the probability of a U.S. recession occurring in 2025 to 60%. These developments represent a material change in the Company's risk environment since the previous Commission orders that will most likely continue through the test year of this case. During this period of heightened risk and volatility, it will be critical for the Company to have an authorized ROE and equity ratio that is supportive of its good credit quality. This will be instrumental in the Company's ability to maintain uninterrupted access to needed liquidity and better withstand potential impacts from fuel price spikes, inflationary pressures, and tightening capital markets. An equity ratio of 50.75% is warranted given the facts and circumstances present in the current case.

Q. What are the customer benefits of the Company maintaining a higher credit rating?

A. The Company provides a critical service that directly impacts customers' quality of life. The Company's ability to deliver long-term investments to the infrastructure that provide safe, reliable, and clean energy will depend on the financial strength of the Company, of which the Company's credit rating is a key indicator. As set forth in the testimony and

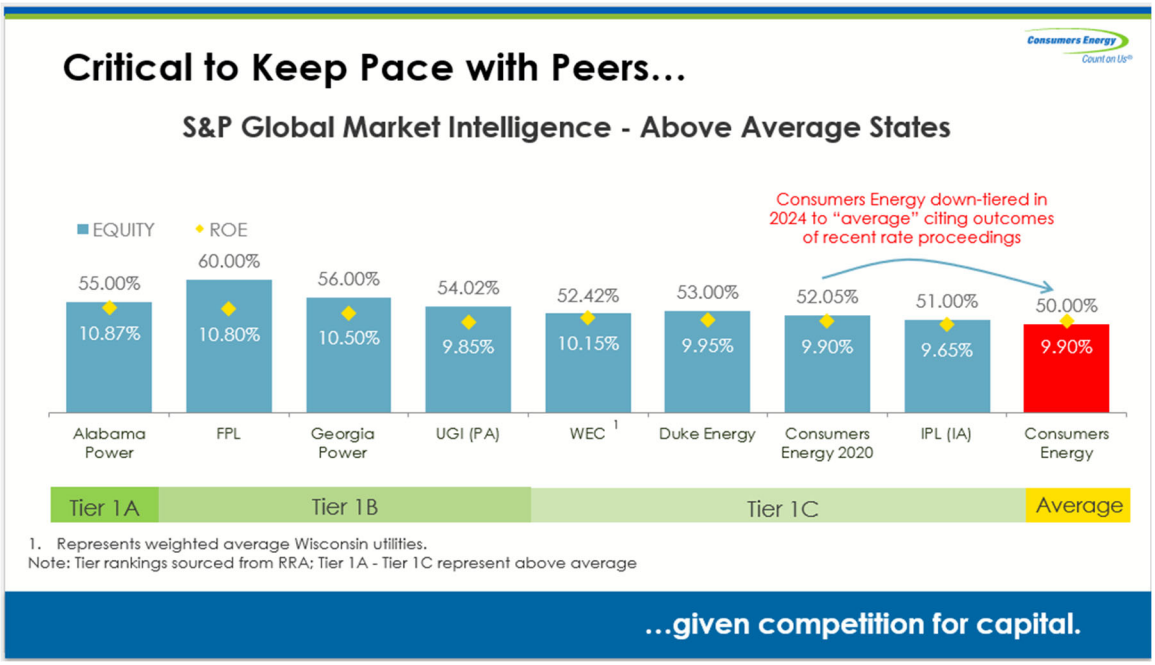
exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments to maintain and improve infrastructure to the benefit of customers. During this time, the Company will rely heavily on the capital markets to fund these investments. Generally, a higher credit rating results in lower financing rates. Therefore, it will be especially important for the Company to maintain strong credit ratings over this period. As shown in Exhibit A-32 (MRB-13), the Company has saved customers $152 million annually as a result of improved credit ratings and lowered interest costs.

The common equity balance and equity ratio projected for the test year in this case also enable the Company to maintain strong credit ratings and better withstand any shocks in the financial markets. An example of this was in March 2023, when Silicon Valley Bank and Signature Bank collapsed, forcing the Federal government to step in and take over the banks. Silicon Valley Bank marked the biggest failure of a United States bank since the 2008 global financial crisis and led to significant market turmoil. Other large banks such as Credit Suisse and First Republic Bank also experienced significant financial pressure caused by the ensuing market panic. Strong credit ratings can help protect customers from spikes in interest rates which increase the cost of capital, and/or inaccessibility to the capital markets which serve as a key source of financing for the Company's investments on behalf of customers. Strong credit ratings can also enable the Company to issue long-term debt ahead of upcoming maturities ("pre-fund") to take advantage of low interest rates and favorable issuance windows without jeopardizing the Company's financial ratios. When market conditions are favorable, refinancing higher interest rate debt at lower rates reduces the Company's overall cost of capital included in customer rates.

iii. Rating Agencies' Assessment of the Regulatory Environment

Q. How else does the equity ratio and ROE impact the Company's credit quality?

A. One component of rating agencies' evaluation of credit quality involves an assessment of the Company's regulatory environment. If the Commission demonstrates a pattern of consistent, constructive rate orders, it contributes favorably to the Company's credit quality and credit rating. The authorized equity ratio and ROE are two important components in the rating agencies' assessment of the regulatory environment. Refer to Exhibit A-33 (MRB-14), S&P's State Regulatory Evaluations – Energy. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average." This is reflected in the following chart:



In downgrading its state regulatory rating, S&P referenced recent rate case decisions in Michigan including authorized ROEs which "compare less favorably" to prevailing industry averages and a "tightening in the regulatory climate." In recent rate case filings, the Company has included this chart, noting that the recent decline in the Company's

weighted rate of return has led to the risk that the Company will no longer be ranked as a utility in an above-average tier jurisdiction. S&P's August 2024 report confirms that this risk has been realized.

Q. Is there evidence that analysts have also started to recognize a decline in the state of the Company's regulatory environment?

A. Yes. In updating its regulatory rankings for U.S. utilities in May 2023, UBS downgraded Michigan from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs ranking in the 3rd quintile as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." Refer to Exhibit A-34 (MRB-15). It is apparent that rating agencies and analysts are taking note of the Company's regulatory outcomes and are viewing them unfavorably. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating. Michigan's above average regulatory standing needs to be protected and bolstered rather than leveraged to justify further credit deterioration and over-leveraging of the Company.

iv. <u>Credit Challenges Facing Regulated Utilities</u>

Q. Have rating agencies commented on the credit quality of regulated utilities as a whole?

A. Yes. Refer to Exhibit A-35 (MRB-16). In a February 2024 report "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens," S&P updated their outlook of the regulated utility industry to negative, citing "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus

equity. Also refer to Exhibit A-40 (MRB-21). In a January 2025 report on North American regulated utilities, S&P highlighted lower ratings headroom as "a high percentage of companies are operating with only minimal financial cushion from our downgrade threshold." S&P also notes that, in 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year. With regards to the industry credit outlook for 2025, S&P identifies the following risks to utilities' credit quality:

- The portion of equity in the industry has been weak and consistently below expectations and thus pressuring the industry's financial measures. S&P states that "without significantly more common equity issuance, we expect the industry's financial measures will continue to weaken, albeit gradually, supporting our negative outlook;"

- Tax legislation could weaken financial measures if the new Republican administration lowers the corporate tax rate, reduces tax credits, or eliminates their transferability; and

- Robust capital spending and challenging regulatory constructs will persist for 2025, further pressuring the industry's credit quality.

S&P also cites Michigan as one of the regulatory jurisdictions that they "continue to carefully monitor." As highlighted earlier in my testimony, there has been a sharp decline in the Company's authorized weighted rate of return following several years of consistent results. It is apparent from this S&P report that a supportive ROE and equity ratio is critical in maintaining a "financial cushion" to protect against downgrade in the event of unforeseen events like the market volatility and disruption that occurred during the onset of the COVID-19 pandemic in 2020 or the financial pressure caused by the dramatic increase in gas prices and interest rates in 2022 or the banking crisis of 2023. These events and rating agency comments highlight the importance for the Company to maintain strong financial metrics and to not manage toward the perceived low end of the credit metric

bands. The Company's ability to continue to provide customers with safe, reliable, and clean energy and make the necessary capital investments is directly tied to the Company's ability to maintain its financial strength.

Q. Is an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case the optimal outcome for the Company and its customers?

A. Yes. This equity ratio and ROE combination is well-measured for both the Company and its customers, while still mindful of the Commission's Order in Case No. U-21585. This results in a weighted rate of return of 5.20% (50.75% x 10.25%), which is 25 basis points higher than the weighted rate of return of 4.95% (50.00% x 9.90%) approved in Case No. U-21585. This capital structure results in a reasonable impact on customer rates while bringing the Company more in-line with the authorized weighted rate of return experienced toward the beginning of the COVID-19 pandemic and prior to the most recent credit rating downgrade. The weighted rate of return as proposed in this case strengthens the Company's balance sheet and credit quality which will be critical in delivering the Reliability Roadmap investments while doing so in the midst of a sustained elevated interest rate environment.

Q. Please explain the long-term debt adjustment of $2.073 billion.

A. I have projected that the average debt balance for the test year ending April 30, 2027, will be $2.073 billion higher than the December 31, 2024 balance. This adjustment consists of the following components:

Long-Term Debt (in millions)			Apr. 30, 2027 Test Year
Month	Issuance	Retirement	Impact
May 2025	$475	$0	$475
Aug. 2025	$650	$0	$650
May 2026	$600	($115)	$448
Aug. 2026	$725	$0	$501
Subtotal			$2,074
Changes in Unamortized Fees			(1)
Total			**$2,073**

The development of the 13-month average long-term debt balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

Q. Please describe the planned debt issuances in May 2025, August 2025, May 2026, and August 2026.

A. Each of these planned debt issuances will be used for general corporate purposes of the Company including financing capital expenditures. The debt planned to be issued in May 2026 will also be used for the retirement of the Company's $115 million 5.24% bonds which mature in May 2026. These planned debt issuances have been determined based on the Company's financing plans after evaluating cash and liquidity requirements for the Company.

Q. What long-term debt was included in developing the 13-month average amount outstanding for the period ending April 30, 2027?

A. Exhibit A-14 (MRB-4), Schedule D-2, shows the long-term debt that was included in developing the 13-month average for the period ending April 30, 2027. The average amount outstanding on line 64, column (j), ties to the 13-month average balance shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

Q. What is your projection regarding the level of short-term debt balance for the test year ending April 30, 2027?

A. I have projected an average short-term debt balance for the test year of $148 million. This balance is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 10, column (b); Exhibit A-14 (MRB-2), Schedule D-1a, page 1, line 10, column (g); and Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 1.

Q. What are the components of the average short-term debt balance?

A. Revolvers, commercial paper, and intercompany borrowing are short-term financing options available to the Company. Revolvers are revolving lines of credit that allow the Company to borrow and repay as long as the outstanding balances remain within the credit limits, or capacity. Commercial paper represents debt issuances under the Company's Commercial Paper Program that are short-term in nature, typically 1- to 90-day maturities. Intercompany borrowing represents short-term borrowings from CMS Energy. Intercompany borrowing is drawn under a promissory note with CMS Energy up to $500 million and carries an interest rate of 1-month Secured Overnight Financing Rate

("SOFR")[1] minus 10 basis points. The Company is the beneficiary of intercompany borrowing to meet short-term liquidity needs when it is available and when it is the most cost-effective alternative. It should be noted that the intercompany borrowing facility is not a dedicated financing option that is always available for the Company to use, but only when CMS Energy has surplus cash and effective borrowing rates must be lower than rates available to the Company under the Commercial Paper Program. The intercompany borrowing facility, therefore, is not considered part of the total liquidity capacity available to the Company.

Q. How was the short-term debt balance of $148 million developed?

A. Exhibit A-14 (MRB-7), Schedule D-6, shows the projected balances, by month, of short-term debt for the test year ending April 30, 2027. I have arrived at these projections after considering the projected total monthly cash flow requirements, planned long-term debt (net) and equity issuances, and the amount of short-term financing available.

Q. Are the projections for short-term debt reflected on Exhibit A-14 (MRB-7), Schedule D-6, expected to be issued under the Company's revolvers, its Commercial Paper Program, or its intercompany borrowing agreement?

A. The Company borrows on its short-term financing facilities in order from least expensive to more expensive. The following is the prioritized order in which the Company utilizes its short-term financing facilities:

[1] SOFR, a benchmark interest rate used in calculating short-term variable interest rates throughout the world. SOFR replaced the London Interbank Offered Rate ("LIBOR") in 2023.

		Amount	**Credit Capacity**
1a.	Commercial Paper	$500 million	$500 million*
1b.	Intercompany Borrowing**	$500 million	
2.	Scotiabank Revolver	$250 million	$250 million
3.	JPMorgan Revolver	$1.1 billion	$600 million*
	Total		$1.35 billion

*Takes away $500 million of the JPMorgan revolver's $1.1 billion capacity (leaving $600 million available).

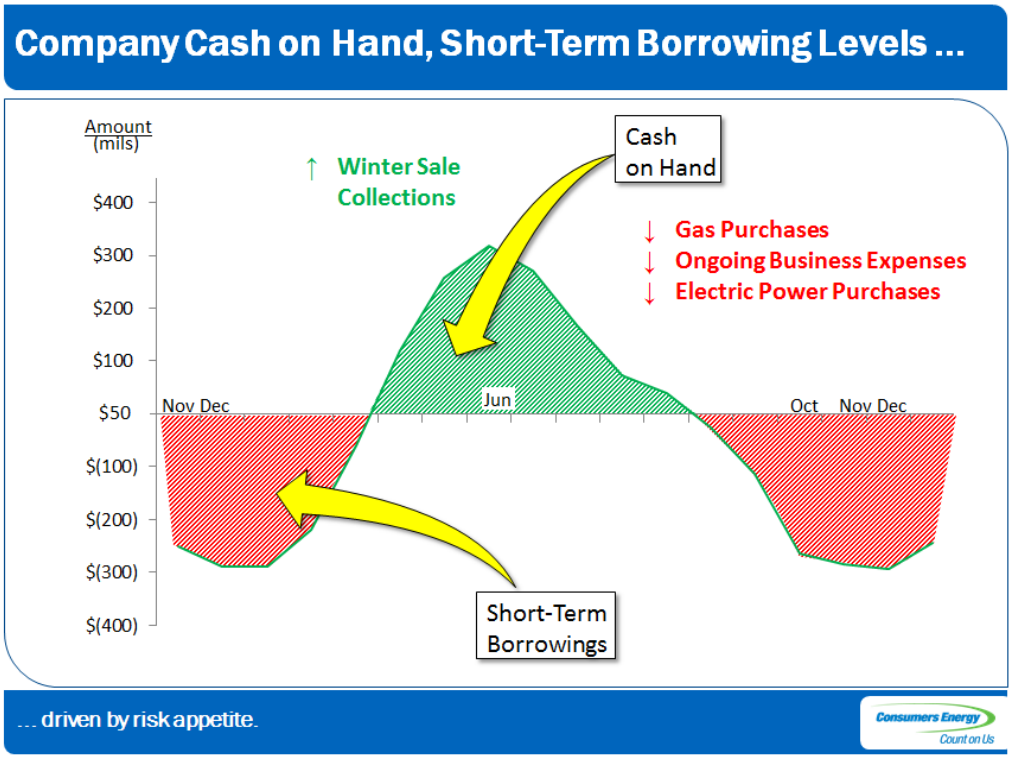
**Intercompany Borrowing or Commercial Paper is used first, depending on availability and which alternative is the most cost-effective at the time of borrowing.

All of the projected test year balances for short-term debt are assumed to be issued under the Company's Commercial Paper Program. This program, along with the intercompany borrowing facility, are the least expensive short-term financing options to the Company and are assumed to be used first when the need arises. The Company's $250 million Scotiabank revolving credit facility is the next least-costly, short-term financing option, with the remaining $600 million revolver ($1.1 billion total capacity less $500 million drawn commercial paper) assumed to be used last.

Q. How does the timing and amount of short-term borrowings fit into the Company's overall liquidity and financing strategy?

A. The Company strives to match long-term investments with long-term financing and to finance short-term liquidity needs with its cash and short-term borrowing facilities. The timing and amount of short-term borrowings is directly related to the level of cash on hand. Due to the seasonal nature of utility cash inflows and outflows, the Company generally holds more cash in the spring and summer months and relies on short-term borrowing in

the fall and winter months. Throughout the year, however, a minimum level of cash on hand is maintained. This is reflected in the following chart which depicts the typical cash and short-term borrowing levels through a given year:



Q. In order to reduce costs, would the Company consider maintaining a permanent layer of short-term debt?

A. No. Short-term financing markets can be volatile and, at times, access to those markets completely disappear, as was witnessed during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil described earlier in my testimony. Based on the experience and judgment of the Company's Treasury Department, as well as members of the Financial Planning and Analysis Department, the Company does not pursue a strategy that maintains a permanent balance of short-term debt. However, the Company does fund seasonal fluctuations in its working capital with short-term debt as previously illustrated. Based on historical trends

of these seasonal fluctuations, the difference between the maximum working capital surplus and the maximum level of working capital deficiency (peak-to-valley) is approximately $300 million to $600 million. The Company is generally comfortable financing between $200 million and $400 million of this gap with short-term borrowings as doing so leaves adequate undrawn capacity in the event of financial market volatility or disruption. In addition, rating agencies assess the Company's liquidity as a component of their overall credit rating methodology. Reducing cash balances and relying consistently on short-term borrowings would weaken the Company's liquidity metrics. Finally, if the Company were to establish and maintain a permanent level of short-term debt, this should be taken into account in calculating the appropriate equity ratio in this case. If the short-term debt balance were included in the debt-to-equity ratio calculation, the required equity balance would need to increase in order to achieve the appropriate 50.75% equity ratio. Doing so would result in a higher overall cost of capital.

Q. How does the Company balance the benefit of carrying sufficient liquidity with the cost of maintaining its short-term credit capacity?

A. The Company's projected $1.35 billion total short-term credit capacity is reasonable and necessary to conduct daily operations and also to keep credit risk at a reasonable level. To maintain strong financial health, it is important for the Company to maintain adequate short-term financing capacity for normal business operations while retaining an adequate amount of additional liquidity for cases of extreme market fluctuations or other unforeseen circumstances. As shown in Exhibit A-14 (MRB-7), Schedule D-6, the Company projects up to $483 million of short-term borrowings, utilizing most of the $500 million capacity of the Commercial Paper Program. Access to the commercial paper market, however,

requires an equivalent amount of revolving credit capacity as a "backstop"; therefore, of the Company's $1.35 billion of revolving credit facilities, $500 million is used to support commercial paper issuance. The remaining $850 million of revolver capacity is a vital backstop for capital expenditures and upcoming long-term debt maturities.

Q. Did the dramatic increase in natural gas prices in 2022 serve as an example of the importance of the Company holding sufficient short-term credit capacity?

A. Yes. The Company generally funds its natural gas purchases using short-term borrowing. Surging demand in the United States combined with national inventory levels below historical averages drove gas prices higher in 2022. In addition, Russia's invasion of Ukraine and the related energy market disruptions further increased gas prices. As a result, the Company had to purchase natural gas at significantly higher prices. In fact, the Company held over $1 billion in short-term debt in November and December 2022, as previously described. While the Company was able to secure a $1 billion term loan in July 2022 to meet the excessive short-term borrowing requirements, access to this type of facility at reasonable interest rates is not guaranteed in the future, particularly during times of extreme capital market volatility or the inability to access those markets as described earlier in my direct testimony. The dramatic increase in gas prices in 2022 and the resulting elevated short-term borrowing levels highlights the importance of maintaining sufficient short-term credit capacity to ensure that the Company is able to adequately fund gas purchases, continue operations, and serve customers.

Q. Has the Company included the renewable liability balance in its projected short-term debt balance?

A. No. Consistent with the Company's RE Plan in Case No. U-21816 filed in November 2024, a renewable liability balance is not expected through the test year of this case. As described earlier in my direct testimony, the capital structure in general rate cases is composed of financing components used to fund its operations and capital investment and includes debt, equity, and deferred income tax balances. Since it would be inappropriate to include an asset balance, the Company has thus excluded this component from the projected capital structure. Refer to Section VI. of my direct testimony for additional details of the Company's treatment of the renewable liability balance.

Q. Please explain the deferred income tax adjustment of $404 million.

A. The Company's Tax Department has projected that the average deferred income tax balance for the test year ending April 30, 2027, will be $404 million higher than the December 31, 2024 balance. This increase is based on projecting book versus tax differences that the Company expects to record from January 2025 through April 2027. These adjustments total $404 million on a 13-month average basis for the test year. The development of the 13-month average deferred income tax balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 4.

Q. How was the ITC balance determined?

A. The Company's Tax Department has projected that the average ITC balance for the test year ending April 30, 2027 will be $148 million, $26 million higher than the December 2024 balance of $122 million. The balance is based on forecasted balances of both existing and anticipated new ITC credits that the Company expects to record from January 2025

through April 2027. These adjustments total $26 million on a 13-month average basis for the test year.

Q. What balances did you use for ITC in the proposed capital structure?

A. I allocated the components for ITC based upon the allocation of long-term debt, preferred stock, and common equity in the recommended capital structure.

B. Development of Cost Rates

Q. Please explain the development of the total weighted cost of capital shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 19, column (g).

A. Column (d) represents the percentage of total capital provided by each of the components of the capital structure shown in column (a). These percentages were developed by dividing the amounts of capital shown in column (b) by the total ratemaking capitalization amount shown in line 19, column (b). Column (e) presents the costs, on a ratemaking basis, of each of the components in total ratemaking capitalization. Column (g) is the after-tax weighted cost of capital and is calculated by multiplying column (d) by column (e). The pre-tax weighted cost is shown in column (i) and is calculated by multiplying column (g) by the conversion factors in column (h).

i. Long-Term Debt Cost Rate

Q. What long-term debt annual cost rate did you use in this case?

A. I developed a 4.54% annual cost for long-term debt. The development of this annual cost rate is shown on Exhibit A-14 (MRB-4), Schedule D-2. Consistent with past Commission practice, the costs are determined on a net proceeds basis. I began with the debt issuances outstanding as of December 31, 2024. I then added the planned new debt issuances in

May 2025, August 2025, May 2026, and August 2026. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, lines 44 through 47.

Q. Why did you use cost on a net proceeds basis?

A. Not reflecting costs on a net proceeds basis would understate costs. The net proceeds methodology accounts for underwriters' compensation and finance expenses. The fees and expenses are shown as a reduction in proceeds from the issuance of new securities, thereby increasing the cost of the issuance over the stated coupon rate.

Q. Please explain the cost rate you assumed for the planned debt issuances in May 2025, August 2025, May 2026, and August 2026.

A. I assumed that all of the planned debt issuances will be 30-year bonds with a fixed coupon (interest) rate. To calculate the total interest rate (coupon) projection for these bonds, I started with the projected 30-year U.S. Treasury rate. For each of these planned debt issuances, I then added a 138 basis point credit spread. These interest rate calculations are shown on Exhibit A-14 (MRB-4), Schedule D-2.

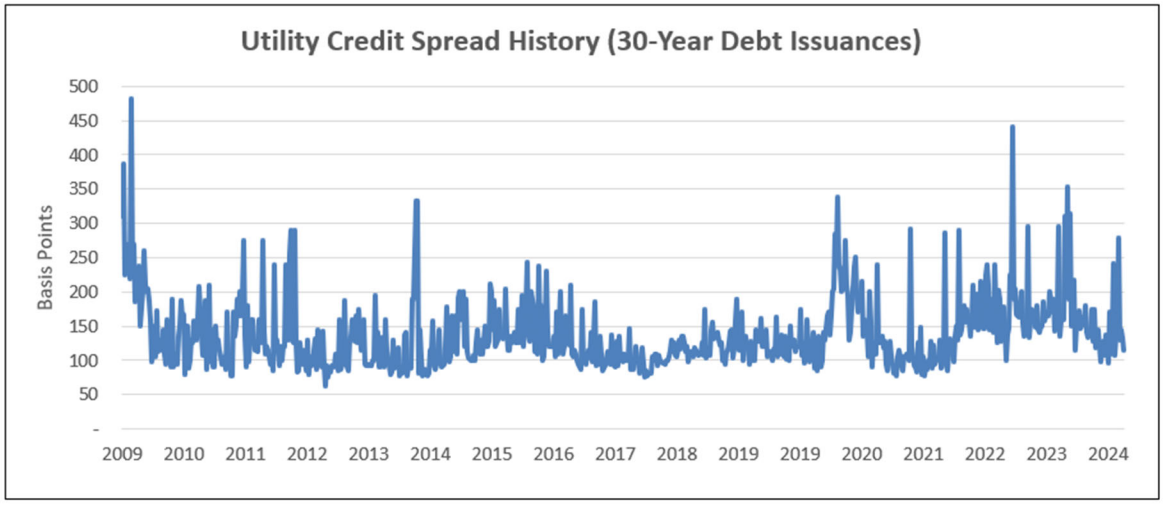
Q. What is a credit spread?

A. A credit spread reflects the compensation investors receive for bearing credit risk of the investment in addition to the underlying Treasury rate. The total interest rate on a corporate bond is the summation of both the Treasury rate and the credit spread.

Q. How did you calculate the credit spread of 138 basis points?

A. Unlike U.S. Treasury rates, credit spreads for long-term bond issuances are not projected by financial forecasting companies. This is because spreads are very difficult to predict. Interest rate spreads are based on a number of factors, most notably the Company's credit rating and the market conditions at the time of the debt issuance, including both same-day

and short-term supply/demand dynamics. In addition, credit spreads can be quite volatile in short periods of time. The volatility of credit spreads is illustrated on the following chart:



Given the lack of a reliable source for projected credit spreads, I applied the calculated average from the last 16 years. From 2009 to Mid-April 2025, the average credit spread on a 30-year debt issuance for investment grade utilities was approximately 138 basis points. This credit spread is very reasonable in relation to the historical spreads for 30-year debt issuances, as evidenced in the chart above.

Q. Are there any existing long-term debt issuances that have variable interest rates?

A. Yes. There are three debt issuances shown on Exhibit A-14 (MRB-4), Schedule D-2, which have variable interest rates. The Floating Rate First Mortgage Bonds ("FMB") issuances shown on line 27 and lines 30 through 31 have variable interest rates.

Q. What cost rates did you use for these variable rate issuances?

A. The interest rate for the Floating Rate FMB issuances is equal to SOFR less 4 basis points. Therefore, I took the projected three-month SOFR for the test year in this case (equal to 3.34%) and subtracted 4 basis points for an interest rate of 3.30%.

Q. Please explain Exhibit A-14 (MRB-4), Schedule D-2, line 58.

A. Exhibit A-14 (MRB-4), Schedule D-2, line 58, represents the amortization of losses on reacquired Consumers Energy debt (including call premium) for refinancings. This amortization needs to be added to the interest cost on the refinanced debt to determine Consumers Energy's true financing cost for the long-term debt. The Commission recognized recoverability of these costs in establishing the cost rate in Case No. U-16794.

Q. How did you calculate the amount shown on Exhibit A-14 (MRB-4), Schedule D-2, line 58?

A. The amount shown on line 58 represents the amortization of losses on reacquired debt with refunding (including call premiums). The projected amortization expense for the 12-month period ending April 2027 is $4,342,000.

ii. <u>Short-Term Debt Cost Rate</u>

Q. What short-term debt cost rate did you use in this case?

A. I used a short-term debt cost rate of 4.92%. This cost rate is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 5.

Q. Please explain the cost of short-term debt.

A. I projected a cost of short-term debt of $7.3 million. The development of this cost is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2. The cost of short-term debt – revolver has four components:

1. **<u>Interest on Borrowings</u>** – Equal to the projected outstanding balance times the projected interest rate. The projected balance, all assumed to be commercial paper, is $148.3 million, calculated on Exhibit A-14 (MRB-7), Schedule D-6. Commercial paper issuances are short term in nature, typically 1- to 90-day maturities. Interest charged on these short-term borrowings are based on several different factors, including market conditions, investor demand, and the tenor (number of days borrowed) of the issuance. I approximated the interest on commercial paper borrowings using the projected SOFR rate for the test year

of 3.34%. This was multiplied by the projected balance of $148.3 million. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $5.0 million for borrowings under the Commercial Paper Program;

2. **Letter of Credit Fees** – Equal to the projected Letters of Credit outstanding times a rate set forth by the facility the Letters of Credit are issued under. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for Letter of Credit Fees. The Letter of Credit Fees shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2, pertain to normal business Letters of Credit to cover ongoing items such as fuel purchases or margin support and also Letters of Credit to cover Midcontinent Independent System Operator, Inc. ("MISO") margin obligations;

3. **Unused (Commitment) Fees** – This cost consists of Annual Revolver Commitment Fees, which the Company is required to pay quarterly to the banks on the "unused" portion of the JPMorgan revolver and the Scotiabank revolver, and other required annual fees under the Revolving Credit agreements. The Revolver Commitment Fees are associated with maintaining fund availability. It should be noted that borrowings under the Company's Commercial Paper Program reduce the "availability" (or the amount the Company is able to draw) of the JPMorgan revolver but do not reduce the "unused" portion of the revolver in calculating the unused (commitment) fees. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.9 million for commitment fees; and

4. **Amortization/Expense of Facility Fees** – At the inception of a revolving credit facility, the borrower is required to pay upfront fees and issuance costs to the lenders. These issuance and upfront costs are amortized over the life of the revolver. For the Commercial Paper Program, there are annual fees required to maintain the facility. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for amortization of upfront revolver fees.

Q. Why is it important to allow for the recovery of commitment fees and amortization of facility fees in addition to the interest on short-term borrowings and interest on letters of credit?

A. These fees and costs are customary in revolving credit facilities and commercial paper agreements and are necessary to secure the financing and to keep the facilities available for the financing needs of the Company. The Company cannot avoid incurring these costs except by giving up the short-term borrowing facilities, which would not be a sound business decision. If these fees are not recovered through short-term debt cost, then they

need to be recovered as part of long-term debt cost. Refer to my later direct testimony which, as directed by the Commission, explains and justifies the cost of the Company's short-term borrowing facilities. The cost of short-term debt – short-term credit facilities represents the cost to provide $1.35 billion of necessary liquidity to Consumers Energy.

iii. Preferred Stock Cost Rate

Q. What is the annual cost of preferred stock?

A. The annual cost of preferred stock is shown on Exhibit A-14 (MRB-6), Schedule D-4. This cost is 4.50%.

iv. Common Equity Cost Rate

Q. What rate did you use for the cost of common equity?

A. Based on my recommended equity ratio of 50.75%, I applied a cost rate of 10.25% for common equity. As explained earlier in my testimony, to the extent that the Commission authorizes a lower equity ratio than that proposed by the Company, a higher ROE is necessary to prevent the potential for adverse credit impacts. The Company's capital structure and ROE recommendations in this case reflect the appropriate levels that the Commission should adopt with that principle in mind in order to preserve Consumers Energy's current credit rating.

v. Other Cost Rates

Q. What cost rates did you use for the remaining components of the capital structure?

A. Consistent with MPSC ratemaking practice, deferred income taxes are included at zero cost. The cost rates for each of the three components of ITC correspond to the cost rates for long-term debt, preferred stock, and common equity.

III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS, AND RECENT UTILITY BOND ISSUANCES

Q. Please describe Exhibit A-27 (MRB-8).

A. Exhibit A-27 (MRB-8) is included per the rate case filing requirements. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides current and historical credit ratings with associated outlooks for the previous five years for the utility and its parent company. Exhibit A-27 (MRB-8) shows Consumers Energy's and CMS Energy's current and historical credit ratings, along with associated credit outlooks, for the previous five years as published by S&P, Moody's, and Fitch Ratings, Inc. ("Fitch"). The credit ratings include senior secured debt, commercial paper, senior unsecured debt, preferred stock, junior subordinated debt, hybrid preferred securities ratings, and preferred stock ratings.

Q. Please describe Exhibit A-28 (MRB-9).

A. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides certain information related to bond issuances. Exhibit A-28 (MRB-9) shows recent public utility corporate bond issuances for a period of three months prior to and three months subsequent to, each of Consumers Energy's long-term public debt offerings issued during the 24 months prior to the date of the Application in this rate case. This summary includes the issue date, issuing company, type of offering (either secured or unsecured), amount of offering, coupon rate, S&P and Moody's credit ratings, maturity date, and spread on U.S. Treasury.

IV. PROJECTED CASH BALANCE

Q. Do you believe that the projected cash balance for the test year ending April 30, 2027, should be based on the 13 months ended December 31, 2024 (the working capital historical period)?

A. No. Using the 13 months ended December 2024 results in a cash balance of $36.4 million, which is lower than is normally expected and required for the Company in the test year of this case.

Q. What do you believe that the projected cash balance for the test year ending April 30, 2027 should be based on?

A. I believe that the projected cash balance for the test year in this case should equate to approximately 1% of test year electric revenues, which results in a cash balance of $50.4 million. This is reflective of normal levels of cash balance.

Q. In its Order in Case No. U-21585 (the Company's previous electric rate case), the Commission instructed the Company in its next electric rate case to "provide further and a more specific explanation as to why its approach in determining its working capital cash balance remains appropriate and should continue to be approved." How do you respond to this order?

A. My testimony describing the key factors and providing evidence that supports the Company's projected test year cash balance of $50.4 million, or approximately 1% of test year electric revenues, is organized as follows:

i. The Company's Cash Projection Approach is Consistent and Balanced

ii. The Company's Cash Projection Approach Minimizes Liquidity Risk

iii. The Company's Actual Cash Balances Have Approximated 1% of Operating Revenues

iv. The Company's Cash Balances Are a Component of Rating Agencies' Assessment of Credit Quality

i. The Company's Cash Projection Approach is Consistent and Balanced

Q. In previous rate cases, has the Company been consistent in projecting the test year cash balance equal to approximately 1% of test year revenues by making an adjustment in order to reduce the projected cash balance for the test year?

A. Yes. The Company has utilized its approach in projecting the test year working capital cash balance consistently and in a balanced manner. Refer to Case Nos. U-21148 and U-20963. In those cases, the historical period included several months in 2020, in which the country experienced extreme volatility, disruption, and illiquidity in the financial markets related to the COVID-19 pandemic. During this time, the Company took a proactive approach by issuing long-term debt and temporarily holding elevated cash balances. These actions limited the Company's risk of being unable to raise needed capital, strengthened the Company's liquidity, and ensured funding for the continued operations of the Company during this uncertain time. As a result of these actions, however, using the historical period that included 2020 in those cases would have resulted in a cash balance that was higher than what is normally expected and required for the Company. As a result, in those cases the Company used cash balances from an alternative historical period that more appropriately reflected normal, lower levels of cash balances. While there are myriad factors that affect cash balances at any point in time (such as weather, storm costs, and gas prices) making actual cash balances higher or lower than expected, the Company

consistently projects normal cash levels which equates to approximately 1% of test year revenues.

ii. The Company's Cash Projection Approach Minimizes Liquidity Risk

Q. Does the Company's projected cash balance for the test year in this case equating to approximately 1% of test year electric revenues reduce liquidity risk?

A. Yes. Having adequate cash on hand reduces the Company's reliance on short-term borrowing facilities for long periods of time. Short-term financing markets can be volatile and, at times, access to those markets completely disappear, as was witnessed during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil. As described earlier in my testimony, the Company does not pursue a strategy that maintains a permanent balance of short-term debt, however, the Company does fund seasonal fluctuations in its working capital with short-term debt. The Company's projected cash balance for the test year in this case is reflective of normal levels of cash that are expected and necessary for the Company to manage working capital requirements and manage financial risk.

Q. In addition to managing financial risk, what are some benefits associated with the Company maintaining a cash balance equal to approximately 1% of test year revenues as projected by the Company?

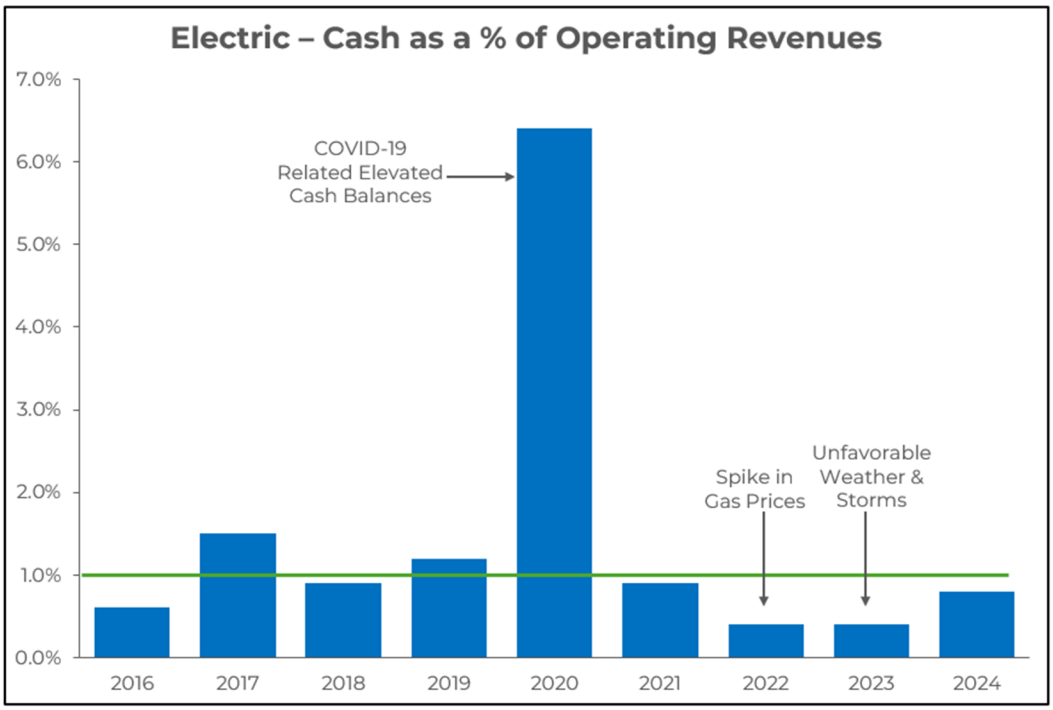
A. In order to obtain an attractive interest rate for long-term bond financing and to minimize the refinancing risk, the Company at times issues new bonds a few months in advance of the actual maturity. Having adequate levels of cash on hand allows the Company additional flexibility in securing the lowest interest rate on its long-term debt issuances which benefits the Company and customers. In addition, given the Company's large capital expenditure

program, the Company aims to maintain an overall liquidity that is sufficient to carry out not only the day-to-day operations but also have the flexibility to meet investing activities should there be a delay in accessing long-term capital from capital markets. For these reasons, the Company's projected cash balance included in working capital for the test year in this case is reasonable and is supportive of the Company's operating, investing, and financing activities.

iii. The Company's Actual Cash Balances Have Approximated 1% of Operating Revenues

Q. Has the Company shown that its actual cash balances have approximated 1% of operating revenues over the last several years?

A. Yes. Refer to the following chart which shows a history of the Company's actual cash balances as a percentage of operating revenues from 2016 to 2024:



The chart shows that the Company's actual cash balances have approximated 1% of operating revenues with the exception of 2020, 2022, and 2023. In 2020, as described

earlier in my testimony, the Company temporarily held elevated cash balances related to the COVID-19 pandemic. In 2022, the spike in gas prices forced the Company to use cash on hand as well as short-term borrowings to fund these higher gas purchases resulting in lower than normal cash balances. In 2023, the Company experienced unfavorable weather as well as storm restoration activity well beyond the five-year historical average. Both of these conditions negatively affected the Company's operating cash flows and cash balances. For the years in which the Company's cash balances were unusually higher or lower than normally expected, the Company adjusted its rate case projected cash balance (higher or lower) to account for these deviations.

iv. The Company's Cash Balances Are a Component of Rating Agencies' Assessment of Credit Quality

Q. Does the Company's cash balance impact its credit rating and credit quality?

A. Yes. For example, S&P uses a quantitative measure in assessing liquidity in its evaluation of the Company's credit quality. With this measure, S&P looks at cash on hand and projected cash sources and uses in determining the Company's "liquidity cushion." In its ratings methodology document, S&P describes liquidity as "an important component of our financial risk assessment across the entire rating spectrum… In our view, unlike most other rating factors that we blend together in assessing an issuer's risk profile, a lack of liquidity could precipitate the default of an otherwise healthy entity." Another rating agency, Moody's, has commented on liquidity as saying "we consider liquidity a key element of our analysis of regulated electric and gas utilities." In assessing the Company's credit quality, Moody's performs a similar analysis of the Company's liquidity cushion and flexibility as S&P, estimating the Company's ability to meet near-term anticipated cash requirements using its available sources. The third major credit rating agency, Fitch, also

has a liquidity measure which is calculated as the amount of readily available cash and credit capacity to service or meet debt maturities and interest obligations. This score indicates if the Company has adequate headroom with cash on hand to cover its operating and short-term liquidity requirements. It is apparent that all three major credit rating agencies consider the level of cash on hand to be an important component of their assessment of the Company's credit quality and credit rating. In summary, the Company has shown that its projection of the working capital cash balance equating to approximately 1% of test year electric revenues results in a level that is needed, reasonable, balanced, and adequately minimizes the Company's financial and credit risk.

V. SHORT-TERM BORROWING FACILITIES

Q. In its Order in Case No. U-21585 (the Company's previous electric rate case), the Commission instructed the Company in its next electric rate case to "explain and justify the size and expense associated with its short-term borrowing facilities if only a very small portion is being or has been utilized. The purpose of such an analysis should be to determine if the size of such borrowing facilities is reasonable and to ensure that the potential benefits of maintaining these facilities is commensurate with their expense." How do you respond to this directive?

A. My testimony will show that the Company's short-term borrowing facilities are appropriately sized, comparable to other utilities, and are utilized in a manner that minimizes liquidity risk to the protection and benefit of the Company and customers.

Q. In its Order in Case No. U-21585, the Commission described the Company's short-term borrowing facilities as "only a very small portion is being or has been utilized." Are the Company's short-term credit facilities also used in a way other than cash draws or borrowing?

A. Yes. As explained earlier in my direct testimony, the Company issues letters of credit to cover ongoing operating activities such as fuel purchases or margin support and also to cover MISO margin obligations. The Company's credit facilities provide a necessary and required backstop against these letters of credit. The use of letters of credit is normal and customary for utilities in conducting ongoing business operations. While not considered a cash draw, the Company is utilizing its credit facilities as issued letters of credit reduce the credit capacity of those facilities.

Q. What are the risks associated with the Company borrowing more heavily on its short-term credit facilities, effectively reducing its credit capacity and total liquidity?

A. To maintain strong financial health, it is important for the Company to maintain adequate short-term financing capacity for normal business operations while retaining an adequate amount of additional liquidity for cases of extreme market fluctuations or other unforeseen circumstances. Just as it would be unwise for families to plan to max out their credit cards, maxing out or borrowing heavily on short-term credit facilities is not a sound liquidity strategy for the Company and customers. Short-term financing markets can be volatile and, at times, access to those markets completely disappear, as was witnessed during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil. Thus, borrowing more heavily on the Company's short-term borrowing facilities creates greater liquidity risk, not to

mention the higher relative cost to draw on those facilities during periods of financial market disruption and interest rate spikes. as explained earlier in my direct testimony, the Company does not pursue a strategy that maintains a permanent balance of short-term debt, however the Company does fund seasonal fluctuations in its working capital with short-term debt. The Company's short-term credit capacity is reasonable and necessary to conduct daily operations and also to keep credit risk at a reasonable level.

Q. How does the cost of the Company's short-term credit facilities benefit the Company and its customers?

A. Short-term credit facilities play a critical roll in supporting the Company's financial strength and stability. Even when there are no outstanding borrowings, the cost of these facilities provides essential protection against unexpected short-term financing market disruptions as described earlier in my direct testimony. This is no different than an individual bearing the cost of a home, auto, or life insurance policy which may not be utilized for periods of time but are nonetheless customary and necessary to maintain in case of unforeseen events. In addition, the Company's short-term credit facilities allow the Company to issue letters of credit which, as explained earlier in my direct testimony, are customary and necessary in conducting normal business operations. Thus, the cost of the Company's short-term credit facilities (even with little or no outstanding borrowings) benefits the Company and customers by providing enhanced financial strength and security and supporting business operations.

Q. Does short-term credit capacity impact the Company's credit quality?

A. Yes. The Company's short-term credit capacity, along with cash on hand, is a component of liquidity. Refer to my earlier testimony which explains how the Company's liquidity is

a key factor in rating agencies' assessment of the Company's overall financial health. Based on guidance issued by all three major credit rating agencies, it is apparent that the Company's liquidity (which includes short-term credit capacity) is an important component of their assessment of the Company's credit quality and credit rating.

Q. Do the rating agencies consider the Company's liquidity including short-term credit capacity to be excessive?

A. No. Refer to Exhibit A-36 (MRB-17). In August 2024, S&P assessed the Company's liquidity, including its short-term credit capacity, as "Adequate," noting that their rating reflected the Company's "prudent risk management." Also refer to Moody's May 2024 credit rating reflected on Exhibit A-37 (MRB-18). In its credit evaluation, Moody's stated "we expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months." Finally, refer to Exhibit A-38 (MRB-19), Fitch's April 2024 credit opinion. In its assessment, Fitch identified the Company's revolving credit facilities as supporting short-term liquidity needs and rated the Company's liquidity as "adequate." It is clear from these reports that the consensus among rating agencies is that the Company's short-term credit capacity is not considered excessive, but is rather "adequate" considering the Company's liquidity needs and provides a suitable cushion to protect against times of economic stress and financial market disruption. A greater reliance on the Company's short-term credit facilities would result in a reduction in that credit capacity, leading to a weakening of the Company's liquidity profile and credit quality.

Q. How does the dramatic increase in gas prices in 2022 highlight the importance of the Company's short-term credit capacity?

A. The spike in gas prices in 2022 forced the Company to use cash on hand as well as short-term borrowings to fund these higher gas purchases. In order to meet the increased short-term borrowing needs caused by significantly higher gas prices while avoiding maxing out its current short-term borrowing facilities, the Company secured a term loan allowing the Company to borrow up to $1 billion. This significantly reduced liquidity risk while ensuring continued short-term borrowing at reasonable interest rates. While the Company was able to secure a $1 billion term loan in July 2022 to meet the excessive short-term borrowing requirements, access to this type of facility at reasonable interest rates is never guaranteed in the future, particularly during times of extreme capital market volatility or the inability to access those markets. The dramatic increase in gas prices in 2022 and the resulting elevated short-term borrowing levels highlights the importance of maintaining sufficient short-term credit capacity to ensure that the Company is able to adequately fund gas purchases, continue operations, and serve customers.

Q. Is the size of the Company's short-term credit facilities in line with that of other utilities?

A. Yes. Refer to Exhibit A-39 (MRB-20). At year-end 2024, peer companies maintained, on average, a ratio of revolving credit facilities to net Property Plant and Equipment of 5.4%. The Company's credit capacity of 5.3% is just below other companies in the utility industry.

Q. Have other utilities been increasing their short-term borrowing capacity?

A. Yes. Refer to Exhibit A-40 (MRB-21). In a January 2025 report on North American regulated utilities, S&P highlights rising capital expenditures over the past decade focused on safety, reliability, and investment in renewable generation. S&P predicts record capital spending in the industry in 2025. As utilities' capital spending has continued to rise, so too has companies' short-term liquidity needs. Recently, there have been multiple examples of other utilities increasing their short-term borrowing capacity. For example, in April 2025, Dominion Energy increased its short-term borrowing capacity by $1.1 billion from $6.9 billion to $8.0 billion, underscoring its commitment to maintaining a strong financial foundation for its operations and future growth initiatives. Also, in March 2025, Southern Company increased its short-term borrowing capacity by $1.0 billion from $7.9 billion to $8.9 billion. Finally, Duke Energy increased its credit facility from $9 billion to $10 billion in March 2025. In its announcement of the credit capacity upsizing, the company noted: "The expansion and extension of the credit facility underscore Duke Energy's commitment to maintaining robust financial health and supporting its operational and strategic initiatives. This development is expected to provide the company with greater liquidity and an extended timeline to leverage financial resources effectively." It is clear that other utilities are increasing their short-term credit capacity in order to meet growing liquidity needs and enhance financial flexibility. An adequate amount of short-term borrowing capacity will also be critical for Consumers Energy as it executes its capital investment plan to support a more reliable, resilient, and increasingly clean energy system for its customers as outlined by the Company's capital witnesses in this case.

Q. Has the Company explained and justified its short-term borrowing facilities as directed by the Commission in Case No. U-21585?

A. Yes. My testimony has shown that the Company's short-term borrowing facilities are appropriately sized and are in line with peer utilities on average. As with other utilities, the Company's robust capital investment plan will require an adequate amount of credit capacity to meet growing short-term liquidity needs. My testimony has also shown that the Company's short-term credit capacity has a direct impact on credit quality and credit ratings, with all three major credit rating agencies assessing the Company's liquidity as "adequate." Finally, my testimony has shown that the Company's utilization of its short-term borrowing facilities is reasonable and prudent and benefits customers by effectively minimizing liquidity risk.

VI. RENEWABLES LIABILITY

Q. In its Order in Case No. U-21585 (the Company's previous electric rate case), the Commission instructed the Company in its next electric rate case to "provide a more thorough explanation of its renewables liability short-term debt process, consistent with the Commission Staff's recommendations in this case." How do you respond to this directive?

A. The primary concern expressed by Staff witness Kirk D. Megginson in Case No. U-21585 was that the renewables liability, representing excess funds collected through the Company's renewable energy program, is improperly "being charged back to customers as a form of short-term debt." However, interest on the renewable liability reduces the revenue requirement in the Company's renewable energy case and is therefore a benefit to renewable customers. In addition, in previous rate cases, the Company has consistently

included the renewables liability as a component of short-term debt in its general rate case capital structure projections consistent with energy legislation. Finally, while not projected or included in the current case, the Company is not opposed to excluding a renewables liability balance from its capital structure should a liability be projected in future cases.

Q. Has the Company's treatment of the renewables liability been in compliance with long-standing ratemaking history and Michigan legal precedent?

A. Yes. Section 21(4) of Public Act 295 of 2008 discusses the cost rate for the renewable liability, and it provides for "the creation of a regulatory liability that accrues interest at the average short-term borrowing rate available to the electric provider during the appropriate period." Although Section 21 was repealed by Public Act 235 of 2023, Section 22(1) of Public Act 235 specifies that previously approved revenue recovery mechanisms under Section 21 remain in effect. The Commission has approved this methodology since the beginning of the renewable portfolio requirements of Public Act 295 in 2008.

Q. If the Company had excluded the renewables liability from its capital structure, would the total cost of capital have decreased?

A. No. Long-term debt and common equity, which make up the vast portion of the Company's capital structure, are more expensive than the renewables liability which is based on short-term interest rates. Therefore, removing the renewables liability from the capital structure would effectively increase (though marginally) the Company's total cost of capital used in the rate case revenue requirement calculation.

Q. Has the Company included the renewable liability balance in its projected short-term debt balance in this case?

A. No. Consistent with the Company's RE Plan in Case No. U-21816 filed in November 2024, a renewable liability balance is not expected through the test year of this case. As described earlier in my direct testimony, the capital structure in general rate cases is composed of financing components used to fund its operations and capital investment and includes debt, equity, and deferred income tax balances. Since it would be inappropriate to include an asset balance, the Company has thus excluded this component from the projected capital structure.

Q. In his direct testimony in Case No. U-21585, Staff witness Megginson recommends that the Commission eliminate the renewables liability balance from the Company's rate case capital structure. Is the Company agreeable to this recommendation?

A. Yes. Although the Company has treated the renewables liability balance consistent with long-standing ratemaking practice and legislative authority, the Company does not object to excluding the renewables liability balance from its capital structure should a liability balance be projected in the future.

VII. RATE OF RETURN NECESSARY FOR LINE CLEARING PROGRAM "RAMP-UP"

Q. What does the Company propose with respect to its Low Voltage Distribution ("LVD") Line Clearing Program expenditures in this case?

A. As detailed in Company witness Patrick D. Daly's direct testimony, the Company is proposing to increase its LVD Line Clearing Program operating and maintenance ("O&M") expenditures significantly above historical levels toward attaining a five-year clearing cycle and more aggressive line clearing on targeted three phase primary lines. The

Company is seeking approval in this case to defer the "ramp-up" related expenses as a regulatory asset once the "ramp-up" begins and through its completion (i.e., beginning in 2026 and through the 2030-2031 test period).

Q. What rate of return must the Company receive on the deferred expenses during the "ramp-up" deferral period?

A. The Company's proposal to securitize the deferred expenses is conditional on the ability to receive the prevailing pre-tax weighted average cost of capital ("pre-tax WACC") on the balance of the regulatory asset until the costs are securitized. Due to the long-term nature of the deferred expenses, the Company intends to fund the "ramp-up" with a mix of long-term debt and equity, aligned with the Company's approved capital structure. Consequently, the appropriate interest rate to be applied to the regulatory asset should be based on the Company's prevailing pre-tax WACC during the "ramp-up" period and until securitization occurs.

Q. Why is the Company's short-term debt rate not an appropriate financing rate for the deferred "ramp-up" regulatory asset?

A. Since the regulatory asset will not be short-term (i.e., less than one year), the Company cannot finance the regulatory asset with debt. Doing so would add additional strain to the Company's credit metrics on top of the strain that has been described throughout this testimony resulting from the material reductions in authorized ROE and equity ratio combined with the unfavorable impacts of the Tax Cuts and Job Act of 2017 and current macro-economic uncertainties. Therefore, using the short-term (or long-term) debt rate would not appropriately match the financing costs with the return the Company earns on the regulatory asset. Thus, the Company's total weighted average cost of capital matches

the "ramp-up" related spending and is the appropriate rate to be applied to the regulatory asset.

Q. Aside from whatever rate of return is applied to the regulatory asset balance, does this "ramp up" in forestry work create any positive FFO, i.e., cash flow?

A. No. It is important to note that forestry spend is an O&M expense and does not create any FFO for the Company in the form of non-cash depreciation expense that gets collected from customers in rates. During the deferral period, the Company would be absorbing the cash and expense burden to fund the "ramp up" while not collecting any of those costs from customers. This deferral has the effect of increasing long-term financing needs for the Company without creating cash flow the way traditional capital does. This makes the application of a pre-tax WACC on this particular regulatory asset balance all the more important.

Q. Please contrast the credit metric ratio impact of the "ramp up" on a standalone basis if a pre-tax WACC or short-term debt rate is applied.

A. Were the regulatory asset funded with short-term debt in lieu of pre-tax WACC, the Company's FFO would be lower and its debt higher, leaving the standalone FFO-to-debt ratio wholly insufficient. These impacts are calculated in the following table:

FFO/Debt Ratio of Forestry Deferral as Standalone

Example: $100 million Regulatory Asset Balance

	As Filed (Pre-tax WACC)	Proforma (Short-Term Debt)
FFO, mils	$ 7.4	$ 4.3
Debt, mils	41.6	84.8
FFO/Debt	**17.7%**	**5.0%**

Calculations (Percentages based on Order in U-21585)

As Filed FFO: $100 mil x 7.38% pre-tax WACC

As Filed Debt: $100 mil x 41.6% LT debt pct of total cap.

Proforma FFO: $100 mil x 4.28% short-term debt rate

Proforma Debt: $100 mil x 84.8% (total cap. less DFIT)

If the prevailing pre-tax WACC is applied, the FFO-to-Debt ratio of the deferral as a standalone would be approximately 18%. It is worth noting, for comparison purposes, that 18% is Moody's downgrade threshold for the Company so this would not add any padding to the Company's position. However, if the same regulatory asset balance is assumed to be financed with short-term debt, the FFO-to-Debt ratio as a standalone would decrease dramatically to approximately 5%. Due to the harmful credit metric impacts, the short-term debt rate is not an acceptable financing assumption for the deferred "ramp-up" regulatory asset.

VIII. SUMMARY AND CONCLUSIONS

Q. Please summarize your recommendations and conclusions.

A. Consumers Energy's capital structure should be based on the capital structure as of December 31, 2024, adjusted for the known and expected changes in long-term debt,

common equity, short-term debt, deferred income taxes, and ITC, as shown on Exhibit A-14 (MRB-1), Schedule D-1. The cost rates developed are fair and reasonable and commensurate with the risks for the period of time rates are expected to be in effect. As shown on Exhibit A-14 (MRB-1), Schedule D-1, I recommend an overall after-tax rate of return of 6.35%. Also, the Company's projected cash balance for the test year in this case should be based on approximately 1% of test year electric revenues, which results in a balance of $50.4 million. Finally, the Company's total weighted average cost of capital should be applied to the regulatory asset associated with the Company's line clearing program ramp up.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Marc R. Bleckman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Marc R. Bleckman who previously filed direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to (i) provide rebuttal to Staff and certain intervenors as it relates to the Company's Low Voltage Distribution ("LVD") Forestry Ramp Up proposal; and (ii) provide rebuttal to certain aspects of the direct testimonies of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Kirk D. Megginson, Attorney General Dana Nessel ("AG") witness Sebastian Coppola, Association of Businesses Advocating Tariff Equity ("ABATE") witness Christopher C. Walters, and Citizens Utility Board of Michigan ("CUB") witness Matthew Bandyk.

Q. How is your rebuttal testimony organized?

A. In Section I, I will provide rebuttal to portions of the direct testimony of Staff and certain intervenors as it relates to the Company's LVD Forestry Ramp Up proposal. In Section II, I will provide rebuttal to portions of the direct testimony of Staff witness Megginson. In Section III, I will provide rebuttal to portions of the direct testimony of AG witness Coppola. In Section IV, I will provide rebuttal to portions of the direct testimony of

ABATE witness Walters. In Section V, I will provide rebuttal to portions of the direct testimony of CUB witness Bandyk.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-187 (MRB-22)	Company Revision to Staff's Exhibit S-4, Schedule D-1 Alternative;
Exhibit A-188 (MRB-23)	Company Revision to Staff's Exhibit S-4, Schedule D-2 Alternative;
Exhibit A-189 (MRB-24)	MPSC Staff's Answer to Consumers Energy's Fourth Discovery Request; and
Exhibit A-190 (MRB-25)	Attorney General's Answer to Consumers Energy's Third Discovery Request.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

I. LOW VOLTAGE DISTRIBUTION FORESTRY RAMP UP

Q. Please describe the Company's proposal with respect to its LVD Line Clearing Program expenditures in this case.

A. As detailed in Company witness Patrick D. Daly's direct testimony, the Company is proposing to increase its LVD Line Clearing Program operating and maintenance ("O&M") expenditures significantly above historical levels toward attaining a five-year clearing cycle and more aggressive line clearing on targeted three phase primary lines. The Company is seeking approval in this case to defer the ramp up related expenses as a regulatory asset once the ramp up begins and through its completion (i.e. beginning in 2026 and through the 2030-2031 test period).

Q. What rate of return should the Commission authorize on the deferred expenses during the ramp up deferral period?

A. As explained on page 52 of my direct testimony, the prevailing pre-tax weighted average cost of capital ("WACC") is the appropriate rate to be applied on the balance of the regulatory asset until the costs are securitized. Due to the long-term nature of the deferred expenses, the Company intends to fund the ramp up with a mix of long-term debt and equity, aligned with the Company's approved capital structure. Consequently, the appropriate interest rate to be applied to the regulatory asset to support this customer investment should be based on the Company's prevailing pre-tax WACC during the ramp up period and until securitization occurs.

Q. In direct testimony, what rate of return did Staff and intervenors propose on the deferred forestry ramp up regulatory asset?

A. On page 8 of Staff witness Duell's direct testimony, Staff recommends that a 4.92% rate be applied to the deferred ramp up expenses, based on the short-term rate proposed in this case. On page 186 of AG witness Coppola's direct testimony, he also recommends the use of a short-term debt rate on the ramp up regulatory asset.

Q. Why is the Company's short-term debt rate not an appropriate financing rate for the deferred ramp up regulatory asset?

A. Refer to pages 52 to 54 of my direct testimony, which provides a detailed explanation of why a short-term interest rate is not the proper rate to apply for this regulatory asset. Since the regulatory asset will not be short term (i.e. less than one year), the Company cannot finance the regulatory asset with debt. Doing so would add additional strain to the Company's credit metrics which is illustrated on pages 53 to 54 of my direct testimony.

Due to the harmful credit metric impacts, the short-term debt rate is not an acceptable financing assumption for the deferred ramp up regulatory asset. The Company's total WACC matches the ramp up related spending and is the appropriate rate to be applied to the regulatory asset.

Q. On page 8 of her direct testimony, Staff witness Duell attempts to justify the application of a short-term interest rate on ramp up spending by referencing the short-term interest rate that the Commission approved for DTE Electric's tree trimming surge program. Is this an appropriate comparison for the Company in this case?

A. No. The interest rate on ramp up spending should be based on the facts and circumstances of this instant case which differ from DTE Electric's request. Refer to pages 16 to 17 of my direct testimony. A high degree of volatility and economic uncertainty has emerged in recent months (and since DTE Electric's order) with respect to financial markets, interest rates, and geopolitical tensions. These developments represent a material change in the Company's risk environment that should be considered in determining the appropriate interest rate to apply to ramp up spending in the instant case. In addition, the Company has numerous cost deferral mechanisms either existing or included for approval in this case.

While the Company is in full support of these expense deferral mechanisms, the cash flow and credit metric impact must also be considered as the Company continues to fund more customer investment ahead of customer collections. During the deferral period, the Company would be absorbing the cash and expense burden to fund the programs while not collecting any of those costs from customers. This deferral has the effect of increasing long-term financing needs for the Company without creating cash flow the way traditional

capital does via non-cash depreciation expense in rates. This makes the application of a pre-tax WACC on this particular regulatory asset balance all the more important. The credit metric degradation associated with using a short-term debt rate for ramp up expenditures described on pages 53 to 54 of my direct testimony would result in a credit metric strain in addition to these expense deferral mechanisms. Due to the harmful credit metric impacts, the short-term debt rate is not an acceptable financing assumption for the deferred ramp up regulatory asset.

Q. Does Staff witness Duell provide any other justifications for proposing a lower rate?

A. Yes. On pages 8 to 9 of her testimony, Staff witness Duell says the Company should receive a lower rate because "the Company has not invested in line clearing like they should have…."

Q. Is this a reasonable justification for proposing a lower rate than the Company can be expected to achieve?

A. No. This appears to simply be a punitive approach based on the witness's opinion that the Company has not prioritized line clearing enough. In taking this approach, Staff witness Duell does not show any concern for the detrimental customer impact of credit downgrades that can come from funding a significant amount of customer investment, such as this ramp up, entirely with debt. Company witness Daly provides further rebuttal on this subject, displaying the consistent annual increases in forestry work which the Company has requested and received authorization from the Commission to spend.

Q. Did Staff propose a higher amount of forestry spending compared to Company position in any of the cases that Staff witness Duell cites?

A. No.

Q. Staff witness Duell proposes a fixed rate of 4.92% be applied throughout the life of the regulatory asset rather than a rate that adjusts with prevailing interest rate environment. Do you agree with that position?

A. No. This is another position that demonstrates Staff's lack of comprehension of capital structure. As described in my testimony on pages 24 through 30, the rate that the Company is subject to with its short-term funding facilities are largely variable in nature based on the prevailing interest rate environment. Therefore, it is an unsound approach to "lock in" the rate applied to this balance, as proposed by Staff. The Company's position of applying the prevailing pre-tax WACC is a sound approach that will adjust for prevailing economic conditions.

Q. Are there any other positions with respect to the Company's forestry ramp up proposal that would have negative credit metric implications?

A. Yes. As explained in Company witness Daly's rebuttal testimony, AG witness Coppola and CUB witness Bunch propose a lower "baseline" O&M expense that represents the amount of funding that is included in rates for the test year. In addition to Company witness Daly's rebuttal testimony explaining why this lower baseline is inappropriate, it should be noted that lower funding and higher deferred costs places undue additional pressure on the Company's credit metrics as a result of lower cash and higher financing that would be necessary as described above. The Company's approach to calculating the baseline expense for the test year is reasonable, well supported by the evidence in this case, and aligned with long-term resiliency objectives. The baseline methodology proposed by Mr. Coppola and Mr. Bunch are without merit and should be rejected by the Commission.

II. REBUTTAL OF STAFF WITNESS MEGGINSON

A. Overview of Areas of Disagreement Addressed

Q. What aspects of Staff's recommendations are you rebutting?

A. I am rebutting Staff's projected common equity balance and the resulting common equity ratio. I am also rebutting Staff's projected cost of long-term debt. Finally, I am responding to Staff's recommendations regarding the Company's short-term credit facilities.

Q. Are there any other aspects of Staff's recommended capital structure that the Company disagrees with?

A. Yes. Consumers Energy does not agree with Staff's recommended Return on Equity ("ROE") of 9.75%. This issue, however, is addressed in the rebuttal testimony of Company witness Ann E. Bulkley, the Company's ROE witness in this case.

B. Rebuttal to Staff's Recommendation Regarding the Common Equity Ratio

Q. Do you agree with Staff's projected common equity ratio of 50.00%?

A. No. Staff's recommended common equity ratio for the test year in this case is understated. My rebuttal testimony to Staff's recommended equity ratio is organized as follows:

i. Staff Incorrectly Interprets the Company's Credit Ratings and Regulatory Environment

ii. Staff Fails to Consider New Circumstances That Justify a Deviation from an Evenly Balanced Capital Structure

iii. Staff Ignores the Potential Negative Financial Impacts of a Lower Equity Ratio

iv. Staff Fails to Consider the Average Equity Ratios of Peer Group Companies

v. Summary

i. Staff Incorrectly Interprets the Company's Credit Ratings and Regulatory Environment

Q. On page 6 of his direct testimony, Mr. Megginson minimizes the importance of Moody's downgrade of the Company's credit rating by stating that the downgrade "put the Company's credit rating more in line with the other two agencies ratings." Mr. Megginson also concludes that "the prior Moody's rating appeared to be an outlier." Do you agree with these statements?

A. No. Each of the credit rating agencies maintains its own ratings methodology and credit rating scale. It is not a universal measure in which the specific credit rating assigned by Moody's, for example, can be directly compared to the credit rating assigned by Standard and Poor's ("S&P") or Fitch. If Mr. Megginson's assertion were true, there would not be a need for more than one rating agency, as all credit rating methodologies and credit rating scales would be the same. Also, Mr. Megginson's attempt to downplay the Company's credit rating downgrade by implying that it was an inconsequential action should be rejected by the Commission. The Company's debt offerings are rated by the three main rating agencies – Moody's, S&P, and Fitch. A lower credit rating indicates higher risk which, in turn, necessitates a higher interest rate to compensate for that risk. Regardless of the presumed comparative credit ratings between the different credit rating agencies, the fact that the Company's credit rating was downgraded by Moody's was a negative event that had negative financial consequences for the Company and for customers who bear the cost of capital.

Q. Starting on page 6 of his direct testimony, Mr. Megginson describes the impact of the Company's regulatory environment on its credit rating. Mr. Megginson also references credit reports in which the Company's regulatory environment has been described as positive. Does this give support to Mr. Megginson's recommendation of a 50.00% equity ratio for the test year in this case?

A. No. I believe that Mr. Megginson's assessment of the Company's regulatory environment is incomplete. In his direct testimony, Mr. Megginson references aspects of Michigan's regulatory framework that have been established for several years under the 2008 and 2016 energy legislation, including items such as a forward-looking test year and the 10-month rate case process. Mr. Megginson's assessment fails to capture the results from the Company's most recent rate cases which demonstrate a sharp decline in authorized weighted rate of return (ROE times equity ratio) following a long period of stability. This recent shift is illustrated in the table on page 15 of my direct testimony. In addition, while rating agencies have described the Company's regulatory environment in a positive light, this rating is continuously evaluated. The persistent decline in the Company's authorized weighted rate of return since 2020 could be seen as a material deterioration in the credit supportiveness of the Michigan regulatory environment. Mr. Megginson fails to acknowledge that the Company's positive regulatory environment in past years has been fueled in large part by authorized ROE and equity ratios that were significantly higher than currently proposed by Staff for the Company in this case. In fact, the trend in rate orders with regard to authorized ROE and equity ratio was a cause for concern for Moody's in its downgrade of the Company's credit rating. An equity ratio of 50.75% and an ROE of

10.25% is better aligned with rate of return levels prior to the Company's credit rating downgrade and is therefore supportive of adequate credit quality at this time.

Q. Is there evidence that analysts have started to recognize a decline in the state of the Company's regulatory environment?

A. Yes. Refer to Exhibit A-33 (MRB-14), S&P's State Regulatory Evaluations – Energy. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average." In downgrading its state regulatory rating, S&P referenced recent rate case decisions in Michigan including authorized ROEs which "compare less favorably" to prevailing industry averages and a "tightening in the regulatory climate." Also refer to Exhibit A-34 (MRB-15). In updating its regulatory rankings for U.S. utilities in May 2023, UBS moved Michigan down a level from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." It is apparent that rating agencies and analysts have taken note of the recent trend in the Company's regulatory outcomes with regard to capital structure. A continuation or, even worse, a further degradation of the authorized weighted rate of return puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating. Michigan's regulatory standing needs to be protected and bolstered rather than drawn upon to push the Company toward over-leveraging. Broadly speaking, an above average regulatory standing translates into increased potential investment which continues to support affordable utility infrastructure financing for the state of Michigan.

Q. On page 7 of his direct testimony, Mr. Megginson references S&P's Regulatory Research Associates ("RRA") report on state regulatory evaluations. Mr. Megginson states that "the Michigan commission is rated Average/1, which is in the upper tier of the national average, in terms of utility credit supportive regulation. Only eight other commissions share Michigan's supportive rating." Do you agree with Mr. Megginson's interpretation of the RRA report?

A. No. Refer to page 9 of the RRA report on Exhibit A-33 (MRB-14). While Michigan is in the higher end of the "Average" tiers, the state is no longer in the "Above Average" category. In addition, 10 other state jurisdictions share Michigan's Average/1 rating and 8 other states are rated higher than the state of Michigan. With 18 other state jurisdictions rated at or above Michigan's, it is misleading to characterize the state as "in the upper tier." As Mr. Megginson notes in his direct testimony, Michigan's regulatory environment was considered above average for a number of years but the outcomes of recent rate case proceedings have led to a reduction of the state's regulatory ranking.

Q. Has S&P provided additional insight with regard to the future credit quality of regulated utilities including Consumers Energy?

A. Yes. Refer to Exhibit A-35 (MRB-16). In a February 2024 report "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens," S&P updated their outlook of the regulated utility industry to negative, citing "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. Also refer to Exhibit A-40 (MRB-21). In a January 2025 report on North American regulated utilities, S&P highlighted lower ratings headroom as "a high percentage of companies are operating with only minimal financial cushion from our downgrade

threshold." S&P also notes that, in 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year. With regards to the industry credit outlook for 2025, S&P identifies the following risks to utilities' credit quality:

- The portion of equity in the industry has been weak and consistently below expectations and thus pressuring the industry's financial measures. S&P states that "without significantly more common equity issuance, we expect the industry's financial measures will continue to weaken, albeit gradually, supporting our negative outlook";
- Tax legislation could weaken financial measures if the new Republican administration…reduces tax credits; and
- Robust capital spending and challenging regulatory constructs will persist for 2025, further pressuring the industry's credit quality.

S&P also cites Michigan as one of the regulatory jurisdictions that they "continue to carefully monitor." It is apparent from these rating agency reports that an ROE and equity ratio combination higher than the current authorized level, and certainly higher than the continued degradation proposed by Staff, is critical to protect the Company from receiving a credit downgrade in light of the credit risks as described above.

Q. On page 8 of his direct testimony, Mr. Megginson includes a chart showing Consumers Energy's net income from 2010 to 2024 noting that the Company's net income has risen over the years which has "enabled Consumers to access credit markets to the tune of billions in short and long-term financing at very competitive rates." Do you agree with Mr. Megginson's interpretation of this data?

A. No. Mr. Megginson reviews the Company's annual change in net income in complete isolation, without considering the changes in investment over time or the changes in rate base. To the extent that the Company has invested in the system over the period from 2010 through 2024, its net income should increase. However, the analysis does nothing to

demonstrate that the increases in net income are sufficient to satisfy the investor-required return on that investment, nor does it conclude anything meaningful about the Company's financial integrity. The Company's access to capital markets and its ability to raise capital at competitive rates is not based on net income, but rather is largely based on the Company's credit quality as determined by credit rating agencies. Since net income can be skewed by non-cash transactions, rating agencies instead look to the Company's cash flow metrics, including its Funds From Operation ("FFO")-to-Debt ratio. Rating agencies also look at the strength of the Company's balance sheet, including its equity ratio. These financial measures are a better indicator of the Company's credit quality and credit rating. It should be noted that the Company's "billions in short and long-term financing" over the years was executed during a period in which the Company's authorized equity ratio was significantly higher than currently proposed by Staff for the Company in this case. As the Company will continue to rely heavily on capital markets to fund capital investment, the Company's proposed equity ratio of 50.75% will help to maintain strong credit ratings and obtain financing at lower interest rates.

Q. On page 8 of his direct testimony, Mr. Megginson points to the Company's debt issuance in 2024 and projected debt issuances in this case as evidence that the Company has not been negatively impacted by Moody's credit rating downgrade. Do you agree with this conclusion?

A. No. Neither the Company's ability to issue debt in 2024 nor the projection of continued debt issuances in this case is evidence that there have been no negative impacts from Moody's credit rating downgrade. As explained earlier in my rebuttal testimony, a lower credit rating results in negative financial impacts associated with a higher cost of capital.

In addition, the Company's debt issuance in 2024 does not prove that the Company will undoubtedly have access to capital markets at reasonable rates in the future, especially with a lower weighted rate of return as proposed by Mr. Megginson.

Q. On page 9 of his direct testimony, Mr. Megginson lists several of the Company's existing and proposed recovery mechanisms, including the Power Supply Cost Recovery ("PSCR") mechanism, Energy Waste Reduction ("EWR") plan, Renewable Energy ("RE") plan, and Integrated Resource Plan ("IRP"). Mr. Megginson suggests that these mechanisms act to insulate the Company from financial risk and thereby justify a lower authorized ROE and equity ratio. Do you agree with this conclusion?

A. No. First, Staff identifies the Company's PSCR which is simply a method for the Company to recover its power costs and is a standard recovery mechanism for electric utilities. Also, Mr. Megginson again references regulatory mechanisms that have been established for several years under state energy legislation. Finally, refer to pages 44 to 45 of Company witness Bulkley's direct testimony which explains that these mechanisms are common for utilities and do not sufficiently reduce risk to justify a lower ROE. Mr. Megginson's claim that these programs support a lower authorized ROE or equity ratio is without merit and should therefore be rejected by the Commission.

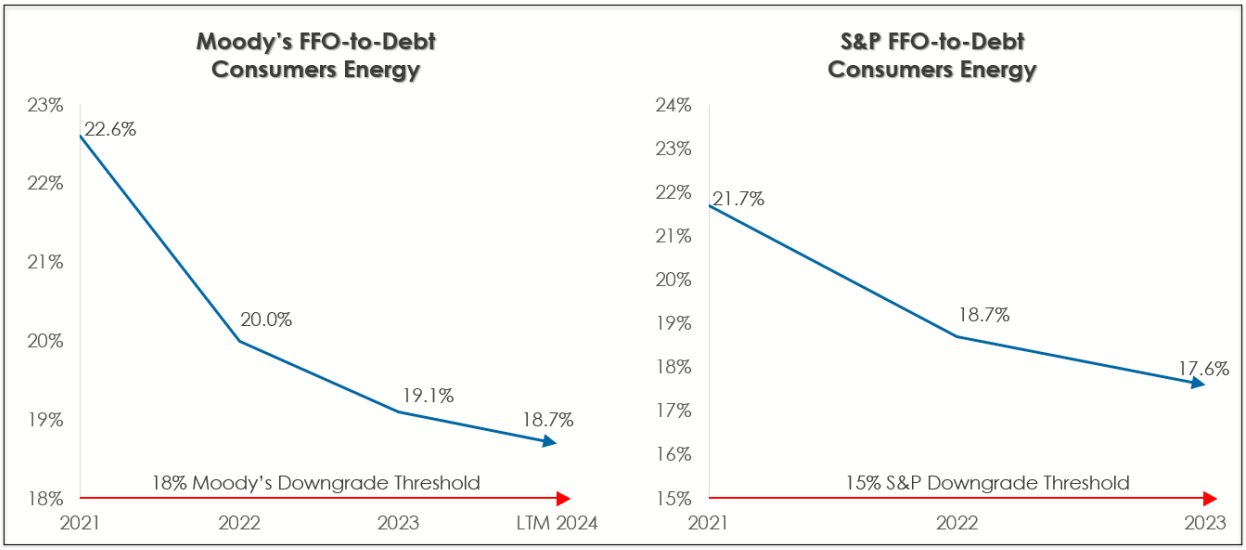
Q. On pages 10 to 11 of his direct testimony, Mr. Megginson references recent credit opinions from S&P, Moody's, and Fitch which describe the rating agencies' expectations with respect to the Company's FFO-to-Debt ratio in future years. Because the rating agencies' expectations are above the credit downgrade thresholds, Mr. Megginson concludes that "the agencies don't foresee any major deterioration or long-lasting decline in the FFO-to-Debt ratio for Consumers Energy in the foreseeable future." Do you agree with Mr. Megginson's conclusion?

A. No. In assessing credit quality, rating agencies must make certain assumptions with respect to the Company's outlook, including future financial results and regulatory outcomes. However, the assumption of credit metrics holding above the downgrade threshold should not be interpreted as assurance that these assumptions will ultimately materialize, with no risk of a credit rating downgrade. For example, in June 2019, Moody's issued a credit opinion for the Company stating that "Consumers' stable outlook reflects our expectation that the Michigan legislative and regulatory environments will remain constructive." Moody's also stated that they expected the Company's FFO-to-Debt ratio to "range between 20% and 24% over the next few years." In May 2021, Moody's downgraded Consumers Energy's credit rating "due to its weakened credit metrics." Moody's also referenced the outcome of recent rate cases which put pressure on the Company's credit metrics. While rating agencies may assume that the Company will continue to operate in a constructive regulatory environment with credit metrics above the downgrade threshold, the Company's credit rating is continuously evaluated. A reduction in the Company's rate of return lowers cash flow, increases debt, and thereby weakens the Company's FFO-to-Debt ratio. These negative credit metric impacts place the Company's credit quality and

credit ratings at risk. The authorized ROE and equity ratio in this case will be a key component of future rating agency evaluations.

Q. In his assessment of the Company's credit ratings and credit quality, did Mr. Megginson take into account the trend in the Company's FFO-to-Debt ratio in recent years?

A. No. As explained on pages 15 to 16 of my direct testimony, the Company's FFO-to-Debt ratio has been trending down in recent years, with a decrease of 350 basis points for Moody's and a decrease of 410 basis points for S&P. These credit metric results are shown in the following chart:



As the Company's FFO-to-Debt ratio deteriorates, moving closer to the rating agencies' credit downgrade thresholds, the credit metric cushion decreases and the Company becomes more at risk for a downgrade. The ROE and equity ratio combination proposed by the Company in this case is critical in protecting the Company from a credit downgrade in light of the credit metric degradation shown above.

ii. Staff Fails to Consider New Circumstances That Justify a Deviation from an Evenly Balanced Capital Structure

Q. On pages 12 to 13 of his direct testimony, Mr. Megginson references the Commission's orders in prior rate cases which reflected the desire for the Company to have a balanced equity ratio. Is this evidence that the Company's equity ratio in this instant case should necessarily be 50% as Mr. Megginson proposes?

A. No. The appropriate equity ratio for the Company should be based on the facts and circumstances presented in this instant case and not predetermined based on prior Commission orders. While the Commission voiced its desire for the Company to move toward a balanced capital structure in the cases referenced by Mr. Megginson, the Commission has also made clear that there should be flexibility in its assessment, allowing for a deviation from an evenly balanced capital structure when circumstances warrant it. This approach is illustrated in the following Commission Orders:

> **Case No. U-17990** – "A more complete analysis should be included to explain why such a result is reasonable and prudent" (when referring to a capital structure that is not evenly balanced). MPSC Case No. U-17990, February 28, 2017 Order, page 64.
>
> **Case No. U-20963** - "The Commission maintains its goal of a capital structure evenly balanced between debt and equity, while continuing to allow a utility to present arguments why a deviation from this ratio is appropriate. As it has done in previous rate cases, the Commission will continue to consider all evidence and circumstances in each rate case to determine the appropriate capital structure." MPSC Case No. U-20963, December 22, 2021 Order, page 200.
>
> **Case No. U-21585** - "The Commission, like the ALJ, acknowledges that there is some degree of flexibility and 'that the aspirational goals expressed in previous Commission orders are not permanently binding and that any target for the Company's capital structure should change if evolving circumstances indicate that the target is no longer a sound policy.'" MPSC Case No. U-21585, March 21, 2025 Order, page 232.

It is clear from previous orders that the Commission does not consider an evenly balanced capital structure a mandate to be followed blindly, but rather as a basis from which a deviation may be justified upon consideration of the evidence and circumstances of each rate case.

Q. Has the Company presented evidence in this case that an equity ratio of 50.75%, slightly above an evenly balanced capital structure, is warranted?

A. Yes. Refer to pages 10 through 22 of my direct testimony in which I outline reasons why an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case are well-measured for both the Company and its customers, while still mindful of the Commission's previous orders. This capital structure results in a modest effect on customer rates while bringing the Company more in-line with the authorized weighted rate of return experienced toward the beginning of the COVID-19 pandemic and prior to the most recent credit rating downgrade. The weighted rate of return as proposed in this case strengthens the Company's balance sheet and credit quality, which will be critical in delivering the Reliability Roadmap investments while doing so in the midst of an elevated interest rate environment.

Q. Are there any new circumstances that give weight to the Company's contention that a deviation from an evenly balanced capital structure to 50.75% equity is justified at this time?

A. Yes. Refer to pages 16 to 17 of my direct testimony. A high degree of volatility and economic uncertainty has emerged in recent months with respect to financial markets, interest rates, and geopolitical tensions. Following the Trump administration's move toward higher tariffs in the spring of 2025, fears of a trade war led to significant market

volatility. The stock market experienced a severe drop in early April, the largest decline since 2020, before recovering. Uncertainty remains over the final scope of trade policy and future tariffs. More recently, as of October 2025, a federal government shutdown is creating market uncertainty and is expected to trigger elevated market volatility. In addition, ongoing conflicts, such as those in the Middle East and between Russia and Ukraine, along with broader geopolitical uncertainty, continue to elevate risk and volatility to U.S. markets. These developments represent a material change in the Company's risk environment since the previous Commission orders that will most likely continue through the test year of this case. During this period of heightened risk and volatility, it will be critical for the Company to have an authorized ROE and equity ratio that is supportive of its good credit quality. This will be instrumental in the Company's ability to maintain uninterrupted access to needed liquidity and better withstand potential impacts from fuel price spikes, inflationary pressures, and tightening capital markets. An equity ratio of 50.75% is warranted given the facts and circumstances present in this instant case.

iii. Staff Ignores the Potential Negative Financial Impacts of a Lower Equity Ratio

Q. Starting on page 14 of his direct testimony, Mr. Megginson references the relatively higher cost of equity compared to debt as justification for a lower equity ratio. Does Staff also discuss the potential negative financial impacts of a lower equity ratio?

A. No. Staff merely states that it is important to "establish a proper equity to debt ratio to maintain reasonable costs to ratepayers." Staff makes this conclusion without analyzing or quantifying the increased costs to the Company and customers that would certainly result from further credit downgrades. Additionally, Mr. Megginson does not provide quantifiable justification as to why his chosen equity ratio of 50.00% is appropriate. This

outcome-based conclusion, which is void of an evidentiary analysis of the resulting financial impacts to the Company and its customers, should not be accepted by the Commission.

Q. Mr. Megginson argues that because equity is more expensive than debt, it necessitates a lower equity ratio. Does this rationale have merit?

A. No. Taken to extreme, this rationale would lead to Staff simply recommending that because customers would benefit most from 0% equity, the Commission should authorize a completely debt financed capital structure for the Company. Such a result would clearly ruin the financial soundness of the Company and a recommendation based on such a rationale should be given no merit. Staff's argument points out the obvious fact that the cost of equity is greater than the cost of debt – but no business can or should fund itself with an excessive level of debt. This simplistic argument adds nothing of value for the Commission to consider.

Q. Although Mr. Megginson chooses to ignore the possibility of another credit downgrade and presents no analysis or discussion of the impacts of a credit downgrade on the Company, what would be the effect of a credit downgrade?

A. Lowering the equity ratio and authorized ROE reduces the Company's overall cost of capital and rate of return. This, in turn, lowers the Company's cash flow and FFO-to-Debt ratio. The negative impacts could cause the Company's FFO-to-Debt ratio to drop below the established rating agency thresholds, placing both the Company's credit quality and credit ratings at risk. While it may seem attractive for the benefit of customers in the near-term to minimize the equity layer of the Company, such a move, and the potential resulting credit rating downgrade, could lead to the Company's customers paying higher

financing costs over the long term, and it could put at risk the Company's ability to execute on its critical investment plan on behalf of customers. Thus, it is of great importance for the regulatory response to be balanced and thoughtful, as the financial health of the Company is a critical element of its ability to implement the capital plan needed to deliver safe, reliable, and clean energy to its customers.

Q. What are the customer benefits of the Company maintaining the needed financial cushion to avoid a credit rating downgrade?

A. A higher credit rating ensures that the Company is able to obtain financing at lower interest rates, resulting in long-term customer rate stability. As shown in Exhibit A-32 (MRB-13), the Company has saved customers $152 million annually as a result of improved credit ratings and lowered interest costs. But the customer benefits extend far beyond this long-term rate stability. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments to maintain and improve utility infrastructure to improve reliability and resiliency to the benefit of customers. During this time, the Company must rely heavily on the capital markets to fund these investments. Therefore, it will be especially important for the Company to maintain strong credit ratings to ensure beneficial access to capital markets for funding to deliver these critical customer investments and enable the Company to do so at the lowest possible financing cost on their behalf. It is also important to note that maintaining credit cushion enables the Company to complete important and emergent customer work ahead of customer costs being reflected in rates when necessary, such as the regulatory deferrals as discussed earlier in my rebuttal testimony. A 50.75% equity

ratio will help ensure that the Company can complete this important customer investment without risking a credit downgrade.

iv. Staff Fails to Consider the Average Equity Ratios of Peer Group Companies

Q. How does Mr. Megginson's recommended 50.00% equity ratio compare to equity ratios authorized by other commissions?

A. Mr. Megginson's recommended 50.00% equity ratio is significantly lower than equity ratios authorized by other commissions. I researched all rate case decisions from 2020 through mid-April 2025 of peer companies and determined the authorized or approved equity ratio for each. This is reflected in Exhibit A-29 (MRB-10). The average authorized equity ratio for the peer group was 51.85%, 185 basis points higher than the 50.00% proposed by Mr. Megginson for Consumers Energy in this case. Despite this higher peer average, I am proposing a ratio of 50.75%, which balances the higher peer average with capital investment plans, credit metrics, customer rate impacts, and the guidance of this Commission, and which continues to support affordable utility infrastructure financing for the state of Michigan.

Q. Are the equity ratios reflected on Exhibit A-29 (MRB-10) based on historical financial data or commission-authorized equity ratios?

A. The equity ratios were taken directly from commission orders and public filings and represent actual regulatory equity ratios authorized or approved by the various commissions across the country, as specifically requested by the Commission on page 218 of its Order in Case No. U-20963. It is clear from this analysis that, on average, regulatory commissions of the Company's peer group are granting equity ratios that are much higher

than the 50.75% requested by the Company in this instant case, and higher still than the 50.00% equity ratio chosen by Mr. Megginson.

Q. Did Mr. Megginson also perform an analysis of average peer company authorized equity ratios?

A. Yes. On page 2 of his Exhibit S-4, Schedule D-5, Mr. Megginson calculated an average authorized equity ratio of 51.07%. This is 107 basis points higher than Mr. Megginson's recommended 50.00% equity ratio in this case and 32 basis points higher than the Company's recommended equity ratio in this case of 50.75%.

Q. On page 22 of his direct testimony, Mr. Megginson refers to his calculated peer equity ratio average of 51.07% and concludes that "the 51.0% average equity layer of Staff's proxy group is primarily due to one outlier equity layer, OGE Energy, with an equity layer well over 53.0%. Removing that firm, the proxy group's average equity layer would be roughly 50.0%, which is in line with Staff's recommendation." Do you agree with Mr. Megginson's interpretation of his average equity ratio analysis?

A. No. Mr. Megginson gives no explanation or evidence as to why the equity ratio for OGE Energy is an "outlier" and should therefore be removed from his analysis. Without such explanation, it appears that Mr. Megginson eliminates this data point solely to lower his average equity ratio calculation to be closer to his recommended equity ratio for the Company. In addition, even if removing OGE's equity ratio from his analysis were appropriate, the revised peer average would be 50.6%, which is "roughly" 51% and is more in line with the Company's recommendation of 50.75% than Staff's 50.00%. Therefore, Mr. Megginson's conclusion regarding his peer equity ratio average is without merit and should be rejected by the Commission.

Q. Is Mr. Megginson's peer equity ratio analysis a valid basis for purposes of authorizing a permanent equity ratio?

A. No. According to Mr. Megginson's exhibit, the source of the equity ratio data is S&P Global Market Intelligence. S&P Global Market Intelligence tracks the authorized equity ratio as a percentage of total capitalization. Total capitalization can be higher (thereby under-reporting an equally comparable equity ratio) because, in addition to permanent capital components, items such as short-term debt, deferred taxes, and customer deposits can be included. For example, as reflected on Exhibit A-14 (MRB-1), Schedule D-1, the Company's 50.75% permanent equity ratio in this instant case translates to only 42.94% on a total capitalization basis that would be reported in Staff's referenced database, which is a difference of 781 basis points. The Company's equity ratio, which is based on a percentage of permanent capital, should only be compared to equity ratios of peer utilities based on percentage of permanent capital in order for the comparison to be at all meaningful. The actual commission-authorized equity ratios provide the required data for a comparable analysis and were relied upon in my analysis shown in Exhibit A-29 (MRB-10) which shows the average equity ratio for the peer group utilizing this method to be 51.85%.

Q. Did Mr. Megginson perform an analysis of the national average peer company authorized ROEs consistent with previous rate cases?

A. Yes. Staff considered average electric utility authorized ROE decisions across the U.S. to support its ROE recommendation for the Company in this case.

Q. If it is appropriate to consider peer average authorized ROE's in determining the recommended ROE for the Company, is it therefore also reasonable to consider peer average authorized equity ratios in determining the recommended equity ratio for the Company?

A. Yes. In its Order in Case No. U-20963, the Commission cited Staff's average ROE analysis as one of the factors considered in determining the Company's approved ROE. In addition, in Case No. U-21585, the Administrative Law Judge ("ALJ") also considered average authorized ROEs in determining the appropriate ROE for the Company. In its Order, the Commission found that the ALJ appropriately considered the record evidence, weighing the vast testimony, methodologies, and proposed ROEs on the record. It is apparent that the Commission considers peer averages an important piece of evidence to inform the ratemaking process. To be consistent with that philosophy, it is appropriate to consider peer company equity ratio averages and trends in determining the equity ratio for the Company in this case.

v. <u>Summary</u>

Q. Please summarize your rebuttal testimony to Staff witness Megginson's recommendation of an equity ratio of 50.00% for the test year in this case.

A. In my rebuttal testimony, I have shown that Mr. Megginson's position on equity ratio is largely not evidence based and that the evidence which he does provide is unsound and should not be relied upon. Further, I have shown that, based on the recent dramatic increase in risk and volatility, a deviation from a balanced capital structure is justified at this time. I have also shown that Staff's recommended equity ratio for the test year in this case is below what is considered supportive of the Company's credit quality and also significantly

lower than the average equity ratio of peer group companies. For these reasons, Staff's recommended equity ratio of 50.00% for the test year in this case should be rejected.

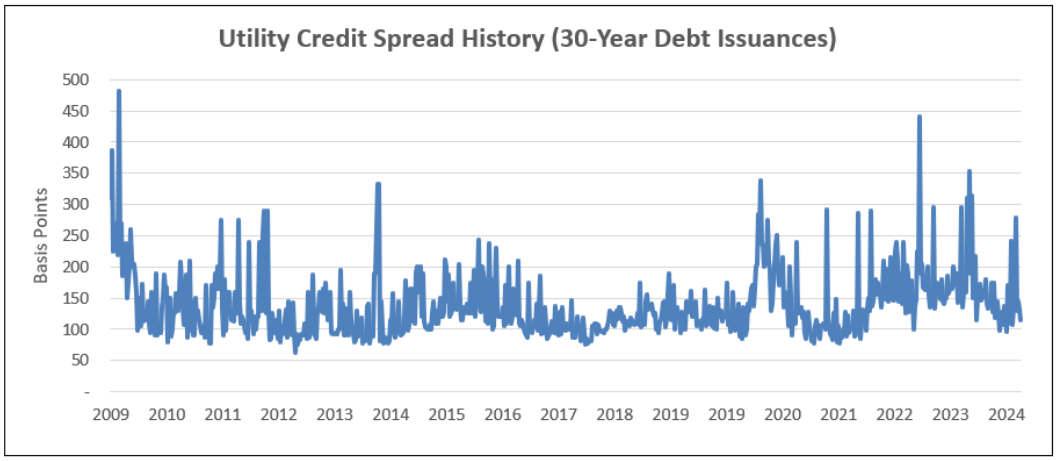
C. Rebuttal of Staff's Recommendation Regarding the Cost of Long-Term Debt

Q. On page 16 of his direct testimony, Mr. Megginson states his intention for Staff to include an updated cost of long-term debt into its revenue deficiency calculation when briefs are filed in this case. This updated cost of long-term debt calculation is reflected in Staff's Exhibit S-4, Schedule D-2 – Alternative. Do you agree with Staff's cost of long-term debt recommendation of 4.37% as reflected on this "alternative" Exhibit?

A. No. While the Company accepts Staff's inclusion of the Company's two long-term debt issuances in May 2025, Mr. Megginson's assumed interest rates on the Company's projected debt issuances in May 2026 and August 2026 are understated. First, current projections for the 30-year U.S. Treasury rate, which serve as the basis for the Company's forecasted debt issuances in 2026, are higher than Mr. Megginson used in developing his cost of long-term debt projections. On his Exhibit S-4, Schedule D-2 Alternative, Mr. Megginson projected a 30-year bond yield of 4.58% in 2026. According to Bloomberg, the projected 30-year bond yield is 4.88% for 2026. In addition, Mr. Megginson's assumed credit spread (added to the U.S. Treasury rate to calculate the total projected interest rate on the new debt issuances) is also unreasonably low.

Q. Mr. Megginson uses the credit spreads on the Company's recent long-term debt issuances as a basis for projecting a 100 basis point credit spread on the Company's forecasted debt issuances through the test year in this case. Is this a reasonable approach?

A. No. As explained on page 32 of my direct testimony, credit spreads for long-term debt issuances are very difficult to predict and can be quite volatile in short periods of time. This is because credit spreads are based on a number of factors, most notably the Company's credit rating and the market conditions at the time of the debt issuance, including both same-day and short-term supply/demand dynamics. The volatility of credit spreads is illustrated on the following chart:



Mr. Megginson's 100 basis point credit spread is also quite obviously at the very low end of the historical spreads for 30-year debt issuances, as evidenced in the chart above. In addition, as shown in Staff's discovery response included as Exhibit A-189 (MRB-24), Mr. Megginson includes credit spreads on the Company's two long-term debt issuances in May 2025 which are <u>not</u> 30-year maturities as a basis for projecting the credit spreads on forecasted debt issuances that <u>are</u> assumed to be 30-year maturities. Credit spreads on debt issuances vary based on the tenure or maturity of the debt issuance (for example, a 10-year

bond versus a 30-year bond). For these reasons, Mr. Megginson's methodology for estimating the credit spread on the Company's projected long-term debt issuances is faulty and should be rejected by the Commission. Alternatively, the Company has provided a very sound approach to projecting credit spreads. Given the lack of a reliable source for projected credit spreads, I applied the calculated average credit spread on a 30-year debt issuance for investment grade utilities from the last 16 years which was 138 basis points. Since credit spreads can be volatile in the short-term, a longer-term historical average is a rational approach with regard to credit spreads.

Q. What is the impact to Staff's projected cost of long-term debt adjusted for these items identified in your rebuttal testimony?

A. Refer to Exhibit A-188 (MRB-23) which shows Staff's cost of long-term debt calculation adjusted for current U.S. Treasury rate projections for the Company's 2026 projected issuances, and the projected credit spread on the Company's 2026 long-term debt issuances of 138 basis points. The result is an increase to Staff's projected cost of long-term debt from 4.37% to 4.43%.

Q. What is the impact on the overall cost of capital compared to Staff's position for the capital structure adjustments you recommend in your rebuttal testimony?

A. The effect of the Company's adjustments to the Staff calculation of overall cost of capital is an increase in the overall cost of capital from 6.03%, as shown on Staff's Exhibit S-4, Schedule D-1 Alternative, to 6.30%. This calculation is shown on Exhibit A-187 (MRB-22) which is the revision to Staff's Exhibit S-4, Schedule D-1 Alternative.

D. Rebuttal of Staff's Recommendation Regarding the Company's Short-Term Credit Facilities

Q. On pages 17 to 18 of his direct testimony, Mr. Megginson expresses his concerns regarding the Company's short-term credit facilities which he considers "excessive" and an "unreasonable cost to ratepayers." Mr. Megginson requests that the Commission disallow the costs associated with the Company's ScotiaBank revolver in future rate cases. Has the Company presented evidence in this case that refutes Mr. Megginson's claims?

A. Yes. In its Order in Case No. U-21585 (the Company's previous electric rate case), the Commission instructed the Company in its next electric rate case to "explain and justify the size and expense associated with its short-term borrowing facilities if only a very small portion is being or has been utilized. The purpose of such an analysis should be to determine if the size of such borrowing facilities is reasonable and to ensure that the potential benefits of maintaining these facilities is commensurate with their expense." The Company responded to this directive in this instant case. Refer to pages 43 to 49 of my direct testimony as well as Exhibit A-39 (MRB-20). My direct testimony shows that the Company's short-term borrowing facilities are:

- Appropriately sized and are in line with peer utilities on average;
- Required to support the Company's robust capital investment plan and to meet growing short-term liquidity needs;
- A key component of the Company's credit quality and credit ratings; and
- Reasonable, prudent, and beneficial to customers by effectively minimizing liquidity risk.

Mr. Megginson's characterization of the Company's short-term credit facilities and recommendation to disallow costs related to the ScotiaBank revolver are misguided, short-sighted, and should be rejected by the Commission.

Q. On page 17 of his direct testimony, in support of his recommendation to disallow future costs associated with the Company's $250 million ScotiaBank revolver, Mr. Megginson claims that the ScotiaBank revolver is "way down the pecking order of short-term funds to be used if required." Do you agree with this statement?

A. No. Refer to page 26 of my direct testimony in which I detail the prioritized order (from least expensive to more expensive) in which the Company utilizes its short-term financing facilities. The $250 million ScotiaBank revolver is second on that list.

Q. On page 17 of his direct testimony, Mr. Megginson states that the Company's ScotiaBank revolver "has never been used since its inception in 2018." Do you agree with this statement?

A. No. The Company's ScotiaBank revolver has been used and is currently being used with multiple letters of credit issued against the facility. These letters of credit are related to the Midcontinent Independent System Operator, Inc. ("MISO") which, as I explain later in my rebuttal testimony, are critical financial instruments in conducting the Company's ongoing business operations. It should be noted that Mr. Megginson includes these letters of credit in his calculation of the total cost of the ScotiaBank revolver.

Q. On page 17 of his direct testimony, Mr. Megginson states that the Company's $58 million in letters of credit associated with the ScotiaBank revolver can simply be "redirected" to the Company's JPMorgan revolver. Do you agree with this statement?

A. No. The JPMorgan revolver has a limit of $100 million for letters of credit issued against the facility. Of that capacity, the Company is currently only able to issue a maximum of $50 million in letters of credit to MISO. Since all $58 million of the ScotiaBank revolver's letters of credit pertain to MISO, the Company would not be able to move them from the ScotiaBank revolver to the JPMorgan revolver as Mr. Megginson suggests. In lieu of issuing letters of credit, the Company could have borrowed against the revolver to satisfy its financial obligations with MISO. However, this would not have been prudent, as it would have resulted in a higher cost to the Company and customers. It should also be noted that, as of September 2025, the letters of credit issued under the ScotiaBank revolver (all with MISO as the beneficiary) total $112 million.

Q. On page 17 of his direct testimony, Mr. Megginson states that "the Company provided scant information on the purpose of the letters of credit and noted that the Letter of Credit was used to cover items such as fuel purchases or margin support for certain services." Do you have anything to add regarding the purpose of the letters of credit?

A. Yes. The use of letters of credit is normal and customary for utilities in conducting ongoing business operations. As explained earlier in my rebuttal testimony, several of the letters of credit issued against the Company's ScotiaBank revolver are with MISO. The letters of credit for MISO are a critical financial instrument for an electric utility participating in MISO's energy and transmission markets. It serves as a form of financial assurance,

guaranteeing that the utility can meet its payment obligations for market transactions, transmission services, and capacity procurements. This is especially important given the volatility of energy markets and the potential for large, unexpected financial exposures. By maintaining these letters of credit, the Company demonstrates creditworthiness and compliance with MISO's tariff-based credit requirements, which helps preserve market integrity and operational continuity.

Q. On page 18 of his direct testimony, Mr. Megginson states that "The Company will tap its Commercial Paper Facility, and then use internal loans from its parent, then likely its JP Morgan Revolver, before the Scotiabank Revolver is even considered." Do you agree with this statement?

A. No. Refer to page 25 of my direct testimony. The intercompany borrowing facility is not a dedicated financing option that is always available for the Company to use, but only when CMS Energy has surplus cash and effective borrowing rates must be lower than rates available to the Company under the Commercial Paper Program. The intercompany borrowing facility, therefore, is not considered part of the total liquidity capacity available to the Company. In addition, refer again to the prioritized order of short-term facility utilization on page 26 of my direct testimony. Contrary to Mr. Megginson's statement, the Company would <u>not</u> draw on the JPMorgan revolver before utilizing the ScotiaBank revolver since the JPMorgan revolver is more expensive.

Q. In his direct testimony, Mr. Megginson considers the Company's short-term credit capacity as excessive. How does the Company (including the Company's Treasury department) evaluate the appropriateness of the size of its total short-term credit capacity?

A. In determining the appropriate size of its short-term credit capacity, the Company aims to minimize financial risk while servicing its short-term liquidity needs at the lowest cost to the Company and customers. To achieve this, the Treasury department conducts assessments of the Company's cash flow requirements, seasonal fluctuations in working capital, and potential events such as significant storm restoration costs or power supply cost volatility. The Company also evaluates its forward-looking capital plan, which includes significant investments to maintain and improve utility infrastructure and to improve reliability and resiliency to the benefit of customers. These investments often require flexible access to liquidity to ensure timely execution and to avoid disruptions or project delays. In addition, the Company evaluates the timing and scale of its upcoming long-term debt maturities, which may require interim financing solutions while permanent refinancing is secured, or may warrant accelerating or postponing debt issuance to optimize cost efficiency. Finally, the Company benchmarks its credit facilities against peer utilities and industry standards to ensure its approach remains prudent and cost-effective (Refer to Exhibit A-39 (MRB-20)). This disciplined and evidence-based evaluation process helps safeguard the Company's credit ratings and ensures that the Company and customers are not exposed to unnecessary financial risk or cost.

Q. Do the rating agencies consider the Company's liquidity including short-term credit capacity to be excessive?

A. No. Refer to Exhibit A-36 (MRB-17). In August 2024, S&P assessed the Company's liquidity, including its short-term credit capacity, as "Adequate," noting that their rating reflected the Company's "prudent risk management." Also refer to Moody's May 2024 credit rating reflected on Exhibit A-37 (MRB-18). In its credit evaluation, Moody's stated "we expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months." Finally, refer to Exhibit A-38 (MRB-19), Fitch's April 2024 credit opinion. In its assessment, Fitch identified the Company's revolving credit facilities as supporting short-term liquidity needs and rated the Company's liquidity as "adequate." It is clear from these reports that the consensus among rating agencies is that the Company's short-term credit capacity is not considered excessive, but is rather "adequate" considering the Company's liquidity needs and provides a suitable cushion to protect against times of economic stress and financial market disruption. A greater reliance on the Company's short-term credit facilities would result in a reduction in that credit capacity, leading to a weakening of the Company's liquidity profile and credit quality.

Q. In his direct testimony, does Mr. Megginson address or attempt to challenge the extensive testimony set forth by the Company in its direct filing with regard to its short-term credit facilities?

A. No. Mr. Megginson does not dispute the Company's direct testimony and exhibit which satisfies the Commission's directive and fully supports the Company's short-term credit capacity. Refer to the Company's analysis on Exhibit A-39 (MRB-20) which shows that the size of the Company's short-term credit facilities are in line (slightly below) that of

peer utility companies. Instead of presenting evidence that would attempt to contradict this analysis, Mr. Megginson merely concludes that the $250 million ScotiaBank revolver is expensive and excessive and should therefore be excluded from the Company's cost of short-term debt. In doing so, Mr. Megginson provides no evidence or analysis that would justify his exclusion or demonstrate why $250 million is not the appropriate amount. Mr. Megginson's recommendation is short-sighted, lacks proper evidence, and should therefore be rejected by the Commission.

III. REBUTTAL OF AG WITNESS COPPOLA

A. Overview of Areas of Disagreement Addressed

Q. What aspects of AG witness Coppola's recommendations are you rebutting?

A. I am rebutting Mr. Coppola's recommendation regarding the common equity ratio. I am also rebutting Mr. Coppola's recommendation regarding the Company's cost of long-term debt. Finally, I am rebutting Mr. Coppola's recommendation regarding the Company's working capital cash balance.

Q. Are there any other aspects of Mr. Coppola's recommended capital structure that the Company disagrees with?

A. Yes. Consumers Energy does not agree with Mr. Coppola's recommended ROE of 9.80%. This issue, however, is addressed in the rebuttal testimony of Company witness Bulkley.

B. Rebuttal to Mr. Coppola's Recommendation Regarding the Common Equity Ratio

Q. On page 107 of his direct testimony, Mr. Coppola references the Commission's Orders in Case No. U-21585 and Case No. U-21389, in which both orders authorized an evenly balanced equity ratio. Mr. Coppola then concludes that the Company's capital structure in this instant case should "similarly mirror" the common equity ratio last approved by the Commission. Do you agree with this conclusion?

A. No. The appropriate equity ratio for the Company should be based on the facts and circumstances presented in this instant case and not predetermined based on prior Commission orders. Refer to my earlier rebuttal testimony to Staff witness Megginson (II.B.ii. Staff Fails to Consider New Circumstances That Justify a Deviation from an Evenly Balanced Capital Structure). While the Commission authorized an evenly balanced capital structure in the cases referenced by Mr. Coppola, the Commission has also made clear that there should be flexibility in its assessment, allowing for a deviation from an evenly balanced capital structure when circumstances warrant it. It is clear from these orders that the Commission does not consider an evenly balanced capital structure a mandate to be followed blindly, but rather as a basis from which a deviation may be justified upon consideration of the evidence and circumstances of each rate case.

Q. Has the Company presented evidence in this case that an equity ratio of 50.75%, slightly above an evenly balanced capital structure, is warranted?

A. Yes. Refer to pages 10 through 22 of my direct testimony in which I outline reasons why an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case are well-measured for both the Company and its customers, while still mindful of the Commission's previous orders. Also refer to my earlier rebuttal testimony to Staff witness

Megginson. There have been new circumstances that give credence to the Company's contention that a deviation from an evenly balanced capital structure is justified at this time including a high degree of volatility and economic uncertainty in recent months with respect to financial markets, interest rates, and geopolitical tensions. As provided for in previous Commission orders, an equity ratio of 50.75% (slightly above an evenly balanced capital structure) is warranted given the facts and circumstances present in this instant case.

Q. Starting on page 110 of his direct testimony, Mr. Coppola references recent credit opinions from Moody's and S&P, noting that the Company's FFO-to-Debt ratio in recent years for both rating agencies was higher than the threshold that could lead to a further downgrade if the Company fell below. For S&P, Mr. Coppola concludes that "these coverage ratios are not indicative of any concerns about a possible debt rating downgrade." Is the Company's FFO-to-Debt ratio in recent years evidence that the Company is not at risk for further credit rating downgrade?

A. No. First, as explained on pages 15 to 16 of my direct testimony and earlier in my rebuttal testimony to Staff witness Megginson, the Company's FFO-to-Debt ratio as calculated by rating agencies has been trending down in recent years – a decrease of 410 basis points for S&P and a decrease of 350 basis points for Moody's. This sizable amount of credit ratio deterioration, which is brushed off by Mr. Coppola, should be troubling to the Commission. Second, while the Company's FFO-to-Debt ratios in previous years were higher than the downgrade threshold, the results cover a time when the Company's equity ratio was significantly higher than Mr. Coppola recommends for the Company in this case - 52.7% in 2021 and 53.2% in 2022. Therefore, Mr. Coppola's statement that there is no concern of downgrade should be discounted by the Commission.

Q. On page 111 of his direct testimony, Mr. Coppola references the increase in the Company's net income in 2024. Mr. Coppola concludes that this will have a positive impact on the Company's credit metrics. Do you agree with this conclusion?

A. No. Refer to my earlier rebuttal testimony to Staff witness Megginson on this issue. Higher net income is not necessarily indicative of higher credit metrics or credit quality. Since net income can be skewed by non-cash transactions, rating agencies instead look to the Company's cash flow metrics, including its FFO-to-Debt ratio. As explained earlier in my rebuttal testimony, this ratio has been trending down in recent years. Rating agencies also look at the strength of the Company's balance sheet, including its equity ratio. Finally, rating agencies evaluate the supportiveness of the Company's regulatory environment, including the authorized ROE and equity ratio. These measures are a better indicator of the Company's credit quality and credit rating. Based on rating agencies' criteria, the weighted rate of return authorized in this case, and not net income, will be a significant factor in determining the Company's credit quality.

Q. On page 112 of his direct testimony, Mr. Coppola refers to the Company's direct testimony which showed that the Company's FFO-to-Debt ratio as calculated by S&P and Moody's has been trending down in recent years. Mr. Coppola dismisses these sharp declines as "temporary" and the result of "unusual and short-term issues." Do you agree with this assessment?

A. No. Mr. Coppola describes events such as unfavorable weather, storm activities, and higher gas prices as the main cause for the Company's decline in credit metrics in recent years. First of all, Mr. Coppola omits that, as explained on pages 15 to 16 of my direct testimony, the decline in the Company's FFO-to-Debt ratio has coincided with recent rate

cases which have resulted in a sharp decline in rate of return (ROE multiplied by equity ratio) having a directly negative result on credit metrics, both historic and future. Secondly, there is no guarantee that these issues that Mr. Coppola describes as "temporary" such as storms, will not persist in future years. For example, from the end of March 2025 through the beginning of April 2025, the Company's service territory was hit with the worst ice storm in northern Michigan in over 100 years, as confirmed by the National Weather Service. At the same time, the lower peninsula of Michigan was hit by thunderstorm systems strong enough to produce 13 confirmed tornados. The restoration costs of this catastrophic storm will have a detrimental impact on the Company's credit metrics into 2027, as they will not be considered for recovery from customers until the Company's next electric rate case filing. In fact, Mr. Coppola's testimony highlighting the negative impact of these events demonstrates the importance of maintaining strong credit metrics in preparation for such events and not managing the Company toward the lower margins.

Q. On pages 113 to 114 of his direct testimony and his Exhibit AG-44, Mr. Coppola references his calculation of the Moody's FFO-to-Debt ratio for the Company for the year ended March 2025 assuming a 9.80% ROE and a 50.0% equity ratio. According to Mr. Coppola's calculations, the Company's FFO-to-Debt ratio would have been 20.0%, or 60 basis points higher for the year ended March 2025 with these assumptions. Do you agree with Mr. Coppola's calculations?

A. No. In his calculations, Mr. Coppola applies a targeted regulatory equity ratio (50.0%) to the Company's actual financial equity ratio (48.4%) calculated from the Company's Securities and Exchange Commission reported balance sheet which is prepared under Generally Accepted Accounting Principles ("GAAP"). Mr. Coppola increases the

pro-forma FFO and decreases the pro-forma debt resulting in a 100 basis point improvement in the pro-forma Moody's FFO-to-Debt ratio. However, there are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. In fact, the Company's equity ratio on a ratemaking basis as of March 2025 was 50.43%. Therefore, to appropriately assess the pro-forma impact of a 50.00% equity ratio, Mr. Coppola should have increased the pro-forma debt and reduced the pro-forma FFO. Mr. Coppola's adjustments to increase common equity from 48.4% to 50% is faulty and results in a pro-forma FFO-to-Debt ratio that is significantly overstated. For these reasons, this calculation should be rejected by the Commission.

Q. On pages 114 to 115 of his direct testimony, Mr. Coppola references recent credit opinions from rating agencies which indicate a stable outlook for the Company. Is this evidence that the Company is not at risk for further credit rating downgrade?

A. No. In assessing credit quality, rating agencies must make certain assumptions with respect to the Company's outlook, including future financial results and regulatory outcomes. However, the assumption of a stable outlook should not be interpreted as assurance that these assumptions will ultimately materialize, with no risk of a credit rating downgrade. For example, Mr. Coppola highlights the rating agencies' assumption that the Company will continue to operate in a constructive regulatory environment. However, the Company's credit rating is continuously evaluated, and the authorized ROE and equity ratio in this case will be a key component of future evaluations. As shown on page 15 of my direct testimony, the results from the Company's most recent rate cases demonstrate a sharp decline in authorized weighted rate of return (ROE times equity ratio) following a long period of stability. The persistent decline in the Company's authorized weighted rate

of return since 2020 could be seen as a material deterioration in the credit supportiveness of the Michigan regulatory environment. In addition, refer to my earlier rebuttal testimony to Staff witness Megginson. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average" referencing less favorable authorized ROEs and a "tightening in the regulatory climate." In updating its regulatory rankings for U.S. utilities in May 2023, UBS also moved Michigan down a level from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." It is apparent that rating agencies and analysts have taken note of the recent trend in the Company's regulatory outcomes with regard to capital structure. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating.

Q. On page 116 of his direct testimony, Mr. Coppola attempts to discredit the Company's inclusion of the May 2023 UBS report of regulatory rankings for U.S. utilities which downgraded Michigan from Tier 1 to Tier 2. Mr. Coppola claims that the Company "mischaracterizes" the report because UBS is not a credit rating agency. Mr. Coppola also considers the report "old information." Do you agree with this assessment?

A. No. While the UBS report was presented under the subsection "Rating Agencies' Assessment of the Regulatory Environment," the Company did not characterize the report as coming from a rating agency. As stated on page 20 of my direct testimony, the question

posed was "Is there evidence that analysts have also started to recognize a decline in the state of the Company's regulatory environment." The UBS report included as Exhibit A-34 (MRB-15) is evidence of this. While UBS is not a rating agency, it is a well-known investment bank that utilizes expert research analysts to examine and report on companies, sectors, and topics in order to guide investment decisions. The UBS regulatory rankings for U.S. utilities is therefore relevant to the Company's assessment of Michigan's regulatory environment in this case. With regard to the fact that the report was published in May 2023, the Company is presenting this report as evidence that entities other than rating agencies have recognized a degradation in Michigan's regulatory environment. The report was published after a sharp decline in rate of return (ROE multiplied by equity ratio) as explained on page 15 of my direct testimony and is therefore still relevant to the Company's testimony in this case.

Q. On pages 116 to 118 of his direct testimony, Mr. Coppola references the Company's Exhibit A-35 (MRB-16), a report by S&P "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens." Mr. Coppola argues that this report should be dismissed because it is "generic" and is "inapplicable to the Company's regulatory and financial position." Do you agree with Mr. Coppola's assessment of this report?

A. No. While certain aspects of this report are not applicable to Consumers Energy, there are also key portions that are directly relevant to the appropriate equity ratio for the Company in this case. For example, in the report S&P cites "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. This concern is relevant in this instant case given that the Company's authorized equity ratio

has decreased 205 basis points from 2019 to present, weakening credit quality and putting the Company's credit rating at risk. S&P also notes utilities as having "strained financial cushion," defined as an FFO-to-Debt ratio less than 100 basis points above a company's downgrade threshold. This is also relevant to the Company in this case given that, as explained in my direct testimony and earlier in my rebuttal testimony, the Company's FFO-to-Debt ratio as calculated by S&P and Moody's has been trending down in recent years, moving closer to the downgrade thresholds for the Company. Finally, the report cites multiple additional credit headwinds that all utilities (including Consumers Energy) are facing including higher interest rates, a narrowing spread between U.S. Treasuries and authorized ROE's, and elevated inflation rates. Therefore, Mr. Coppola's assertion that the Commission should dismiss this relevant industry report should be rejected. It should also be noted that, on page 117 of his direct testimony, Mr. Coppola acknowledges that the Company has minimized financial risk by not maintaining a significant amount of short-term debt and instead borrowing on a "seasonal" basis.

Q. On page 118 of his direct testimony, Mr. Coppola references the Company's Exhibit A-40 (MRB-21), a January 2025 report from S&P on North American regulated utilities. Mr. Coppola attempts to downplay the risks to utilities' credit quality identified in the report as not being applicable to Consumers Energy. Do you agree with Mr. Coppola's assessment of this report?

A. No. Refer to page 21 of my direct testimony. One of the risks identified by S&P in the report is the weakening of utilities' equity layer. Specifically, S&P states "The portion of equity in the industry has been weak and consistently below expectations and thus pressuring the industry's financial measures." S&P also states that "without significantly

more common equity issuance, we expect the industry's financial measures will continue to weaken, albeit gradually, supporting our negative outlook." The Company's equity ratio has decreased significantly in recent years. Therefore, despite Mr. Coppola's assessment, this report is relevant and directly applicable to determining the appropriate equity ratio for the Company in this case.

Q. Beginning on page 119 of his direct testimony, Mr. Coppola states that "common equity capital infusions into Consumers Energy by the parent company are being funded to some extent by long term debt." He cites "financial transactions" between Consumers Energy and CMS Energy. Do you agree with these statements?

A. No. Mr. Coppola's assertion that equity investments into the Company from Consumers Energy's parent company, CMS Energy, are the result of CMS Energy borrowing debt and investing the proceeds into the Company is inaccurate and unsupported. The timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy. Equity infusions are determined after considering the capital spending and financing needs of Consumers Energy. The goals of the parent company include maintaining a strong and healthy utility, capable of serving the needs of its customers. This commitment is reflected in the equity infusions from the parent company to Consumers Energy over the last several years and the resulting actual equity ratio.

Q. On page 121 of his direct testimony, Mr. Coppola provides an analysis of the capital structure of CMS Energy and Consumers Energy from 2010 to 2024, attempting to link changes in long-term debt and equity between the two companies. Does this analysis have any merit in this instant case?

A. No. As explained above, the timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy. Also, in Case No. U-18124 the AG made this same argument that Consumers Energy's equity balance is, at least in part, funded by long-term debt from its parent company. In its July 31, 2017 Order in Case No. U-18124, the Commission adopted the findings and recommendations of the ALJ, who determined this argument from the AG "has been considered and rejected by the Commission." Mr. Coppola's analysis has been found to have no merit in the past and should again be rejected.

Q. On page 123 of his direct testimony, Mr. Coppola's argument for setting a 50.00% equity ratio in this case is that the common equity ratio of his peer group was 42.2% in 2024, as shown on his Exhibit AG-38. Is this an appropriate comparison to the projected common equity ratio in this case?

A. No. The average equity ratio calculation for the proxy group on Mr. Coppola's Exhibit AG-38 uses the equity ratio at the parent holding company level and is, thus, a misleading and inappropriate comparison. As the Company has repeatedly explained in response to this exact same argument by the AG over the years, ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items and provides a completely inappropriate point of comparison. Mr. Coppola continues to avoid addressing this discrepancy. Perhaps the 780 basis point differential between the results of his analysis

on Exhibit AG-38 and his own recommendation points to Mr. Coppola's recognition that the analysis does not provide a relevant comparison. In addition, Mr. Coppola's analysis is further skewed because the sources for Mr. Coppola's debt and equity balances are Securities and Exchange Commission reported financial statements, which are prepared under GAAP. There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. These differences could easily further distort the equity ratios calculated on Mr. Coppola's Exhibit AG-38.

Q. Is Mr. Coppola's average peer group equity ratio analysis in line with the Commission's stated expectations?

A. No, the Company is the only party in this case that has provided peer equity ratio analysis that is in line with the Commission's stated expectations. In its Order in Case No. U-20963, the Commission stated that "regulatory and financial data should not be combined" in such an analysis. Further, the Commission deemed in its Order in Case No. U-20963 that such an analysis is invalid assuming one "could not verify that its data contained equity ratios set by a regulatory commission in a rate case." In his analysis of a proper equity ratio for the Company, Mr. Coppola ignores this Commission's direction by consistently utilizing equity ratios based, in part, on financial, and not regulatory, data. He consistently utilizes equity ratios that do not arise out of Commission orders, and he further fails to explain the basis or rationale for doing so. As a result, the AG's equity ratio analysis should be rejected as outside the methodology required by the Commission.

Q. If equity ratios on a financial basis are not considered relevant, what is the more appropriate comparison of average utility equity ratios?

A. It is clear from the Commission's Order in Case No. U-20963 that actual commission-authorized equity ratios is the preferred data source for an average equity ratio analysis. I refer to my Exhibit A-29 (MRB-10) in which I researched all rate case decisions from 2020 through mid-April 2025 of peer regulated companies and determined the authorized or approved equity ratio for each. The equity ratios used for comparison purposes were taken from commission orders and public filings and represent actual regulatory peer equity ratios authorized or approved by different commissions across the country. The average equity ratio for the peer group was 51.85%. This is significantly higher than the equity ratio recommended for Consumers Energy's capital structure in my rebuttal testimony and is also 185 basis points higher than the equity ratio Mr. Coppola recommends for the Company in this case. Despite this higher peer average, I am proposing a ratio of 50.75%, which balances the higher peer average with capital investment plans, credit metrics, customer rate impacts, and the guidance of this Commission, and which continues to support affordable utility infrastructure financing for the state of Michigan.

Q. On pages 123 through 126 of his direct testimony, Mr. Coppola attempts to discredit the Company's calculation of the peer group average commission-authorized equity ratios reflected on Exhibit A-29 (MRB-10). Do these arguments have merit?

A. No. The Company adhered to an established selection criteria outlined on Exhibit A-29 (MRB-10). Mr. Coppola's claims are false and divert attention away from his own lack of meaningful comparisons, meaningful criteria, and meaningful analyses of various utilities,

commission decisions, and basis for equity ratios. As explained in my direct testimony and earlier in my rebuttal testimony, the Company's data source is responsive to previous Commission orders and serves as a valid benchmark for the appropriate equity ratio for the Company in this case. As I will show in my following rebuttal testimony, Mr. Coppola's issues with Exhibit A-29 (MRB-10) are completely baseless and are an attempt to devalue the compelling evidence put forth by the Company that average peer company equity ratios are significantly higher than what Mr. Coppola proposes for the Company in this case.

Q. On page 124 of his direct testimony, Mr. Coppola argues that the inclusion of equity ratios awarded to gas utilities "inflates the outcome" of the Company's peer authorized equity ratio analysis. Does the inclusion of gas utilities in its analysis discredit the Company's peer authorized equity ratio analysis?

A. No. First, the Company calculates an average equity ratio for the gas utilities included in the exhibit as 52.51% and the average for the electric utilities as 51.58%. These are both approximately in line with the average for all companies in the exhibit of 51.85%. Therefore, Mr. Coppola's contention that the gas utility equity ratios are inflating the outcome of the analysis is exaggerated. Second, as explained earlier in my rebuttal testimony, the Company adhered to an established selection criteria outlined on Exhibit A-29 (MRB-10) which included a scope of <u>all</u> regulated subsidiaries of the Company's ROE proxy group. The purpose of the Company's Exhibit A-29 (MRB-10) is to provide a benchmark of equity ratios recently authorized by other commissions across the country. The fact that some of the regulated subsidiaries are gas utilities does not discredit or minimize the value of the analysis, as it is still a representative sample of recent rate case decisions.

Finally, it should be noted that in prior rate cases in which the Company presented this same exhibit, Mr. Coppola faulted the Company for including companies that were not part of the ROE proxy group in those cases. While the Company rejected that argument, in this instant case the Company ensured that all peer utility companies included in the analysis were regulated subsidiaries of the ROE proxy group. Regardless of this fact, Mr. Coppola continues to take issue with the composition of utilities in the Company's peer authorized equity ratio analysis.

Q. On page 124 of his direct testimony, Mr. Coppola claims that the Company's peer average authorized equity ratio reflected on Exhibit A-29 (MRB-10) is overstated as a result of the inclusion of smaller companies which "tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage." Do you agree with this conclusion?

A. No. Mr. Coppola presents no evidence showing a correlation between a company's size and its authorized equity ratio. Refer to Exhibit A-190 (MRB-25). When asked in discovery for analyses, studies, or reports supporting this statement, Mr. Coppola indicated that he "relied on his knowledge and experience." In his discovery response 3-CE-AG-5 Attach 1, Mr. Coppola also included an excerpt from Dr. Robert Morin's book New Regulatory Finance which discusses the relationship between company size and investment risk and return. This is a separate issue from the impact of a company's size on its authorized equity ratio and does not support Mr. Coppola's claim. Therefore, Mr. Coppola's assumption that the inclusion of certain "smaller" companies results in an overstatement of the peer average is unsupported and should be rejected. In addition, Exhibit A-29 (MRB-10) is intended to be an informative survey of <u>all</u>

commission-authorized equity ratios for utilities across the country and not filtered to adjust for or exclude companies with certain characteristics (customer count, rate base size, etc.). Finally, Mr. Coppola again presents a criticism of the Company's peer equity ratio analysis without offering an alternative analysis that he believes to be more representative of commission-authorized equity ratios. Mr. Coppola performs no analysis at all, but rather simply relies on the average equity ratio calculation for the parent holding companies of his proxy group of 42.2%. As explained earlier in my rebuttal testimony, this approach is flawed and should not be relied upon in this case.

Q. On page 125 of his direct testimony, Mr. Coppola claims that the equity ratio for Alliant Energy's Wisconsin Power & Light should be 53.7% instead of 55.09% as reflected on the Company's Exhibit A-29 (MRB-10). Is this a valid claim?

A. No. As shown on Exhibit A-14 (MRB-1), Schedule D-1, the Company's projected equity ratio of 50.75% excludes short-term debt. The 53.7% equity ratio for Wisconsin Power & Light referenced by Mr. Coppola is on a total capital structure basis which includes short-term debt and is therefore not comparable to the average peer authorized equity ratio analysis in this case. Wisconsin Power & Light's authorized equity ratio on a permanent capital basis (excluding short-term debt and comparable to the Company's 50.75%) is 55.09% and was correctly included in the Company's Exhibit A-29 (MRB-10).

Q. On page 125 of his direct testimony, Mr. Coppola claims that the equity ratio for Duke Energy Progress – North Carolina should be 50.5% instead of 53.0% as reflected on the Company's Exhibit A-29 (MRB-10). Mr. Coppola cites page 15 of Duke Energy's 2024 Form 10-K as support for this claim. Is this correct?

A. No. Duke Energy Progress – North Carolina was authorized a 53.0% equity ratio in August 2023. Page 15 of Duke Energy's 2024 Form 10-K validates this as shown below:

	Regulatory Body	Revenue Increase (Decrease) (in millions)	Return on Equity	Equity Component of Capital Structure	Effective Date
Approved Rate Cases:					
Duke Energy Indiana 2024 Rate Case	IURC	$ 385	9.75 %	53 %	March 2025
Duke Energy Florida 2024 Rate Case[a]	FPSC	203	10.3 %	53 %	January 2025
Duke Energy Carolinas 2024 South Carolina Rate Case	PSCSC	150	9.94 %	51.21 %	August 2024
Duke Energy Carolinas 2023 North Carolina Rate Case[b]	NCUC	768	10.1 %	53 %	January 2024
Duke Energy Kentucky 2022 Kentucky Electric Rate Case[c]	KPSC	48	9.75 %	52.145 %	October 2023
Duke Energy Progress 2022 North Carolina Rate Case[d]	NCUC	494	9.8 %	53 %	October 2023
Duke Energy Progress 2022 South Carolina Rate Case	PSCSC	36	9.6 %	52.43 %	April 2023
Duke Energy Ohio 2021 Ohio Electric Rate Case	PUCO	23	9.5 %	50.5 %	January 2023
Duke Energy Florida 2021 Settlement agreement[e]	FPSC	195	9.85 %	53 %	January 2022
Pending Rate Cases:					
Duke Energy Kentucky 2024 Kentucky Electric Rate Case	KPSC	70	10.85 %	52.728 %	July 2025

Contrary to Mr. Coppola's claim, Duke Energy Progress – North Carolina's authorized equity ratio of 53.0% was therefore correctly included in the Company's Exhibit A-29 (MRB-10).

Q. On page 125 of his direct testimony, Mr. Coppola claims that the Company's Exhibit A-29 (MRB-10) "excluded utility companies in the northeastern part of the United States where ROEs and equity ratios tend to be lower." Is this a valid claim?

A. No. In its analysis of peer group authorized equity ratios, the Company did not exclude any region of the country aside from in-state proxy DTE Energy and the Company. The Company's selection criteria included all regulated subsidiaries of the Company's ROE proxy group who had rate orders issued from January 2020 through mid-April 2025. Mr. Coppola's claim that the Company intentionally excluded certain Companies from its analysis is therefore without merit and should be rejected by the Commission.

Q. What evidence did Mr. Coppola provide in support of his claim that equity ratios for utilities in the northeastern part of the United States tend to be lower?

A. Refer to Exhibit A-190 (MRB-25). In a discovery response to the Company on this subject, Mr. Coppola provides a list of utilities in the northeastern part of the United States and the recently authorized equity ratios for each of those companies.

Q. Do you believe that the equity ratios presented by Mr. Coppola in his discovery response to the Company could be understated?

A. Yes. According to Mr. Coppola's discovery response, the source of the equity ratio data is RRA which tracks the authorized equity ratio as a percentage of total capitalization. As described earlier in my rebuttal testimony, total capitalization can be higher (thereby under reporting an equally comparable equity ratio) because, in addition to permanent capital components, items such as short-term debt, deferred taxes, and customer deposits can be included.

Q. Would the companies listed in Mr. Coppola's discovery response have been appropriate to include in the Company's peer average authorized equity ratio analysis?

A. No. While Mr. Coppola lists equity ratios for companies in the northeastern part of the United States, the companies listed do not meet the selection criteria set forth on the Company's Exhibit A-29 (MRB-10). In addition, several of the companies listed would be improper to include in the Company's average peer authorized equity ratio analysis according to Mr. Coppola's own stated criteria. For example, on page 124 of his direct testimony, Mr. Coppola argues that smaller companies (using customer count as a measure) should be excluded from the average equity ratio analysis. However, some of the

companies listed by Mr. Coppola in his discovery response are in fact smaller companies. Green Mountain Power, for example, serves approximately 275,000 customers. Versant Power serves approximately 165,000 customers, and Fitchburg Gas & Electric serves approximately 47,000 customers. In addition, as explained earlier in my rebuttal testimony, Mr. Coppola has insisted that all of the companies in the average authorized equity ratio analysis should be regulated subsidiaries of the ROE proxy group. However, several of the companies Mr. Coppola lists in his discovery response are not regulated subsidiaries of either Mr. Coppola's or the Company's ROE proxy group. In summary, Mr. Coppola has not provided sufficient evidence that the Company improperly excluded utility companies in the northeastern part of the United States in its peer average authorized equity ratio analysis or that these companies would have reduced the Company's overall result.

C. Rebuttal To Mr. Coppola's Recommendation Regarding the Cost of Long-Term Debt

Q. Starting on page 127 of his direct testimony, Mr. Coppola recommends that the Company's cost of long-term debt be lowered 15 basis points from 4.54% to 4.39%. Mr. Coppola states that his lower cost of long-term debt incorporates the Company's actual long-term debt issuances in May 2025 as well as a lower projected 30-year U.S. Treasury rate than assumed by the Company for the projected 2026 issuances. Do you agree with Mr. Coppola's adjusted cost of long-term debt rate?

A. No. Refer to my earlier rebuttal testimony to Staff witness Megginson and Exhibit A-188 (MRB-23). While I agree that it is appropriate to adjust the Company's projected cost of long-term debt for the May 2025 debt issuances and for current U.S. Treasury rate projections, the resulting adjusted cost of long-term debt is 4.43%. This adjusted cost of

long-term debt projection is reflected in Exhibit A-188 (MRB-23) – The Company Revision to Staff's Exhibit S-4, Schedule D-2 Alternative.

D. Rebuttal to Mr. Coppola's Recommendation Regarding the Working Capital Cash Balance

Q. On pages 99 to 105 of his direct testimony, Mr. Coppola discusses his recommendation to reduce the Company's projected test year working capital cash balance by $41.4 million to $9.0 million. How do you respond?

A. I will address specific issues raised by Mr. Coppola below, but I refer back to pages 38 to 43 of my direct testimony in which I provided extensive evidence that the Company's projection of the working capital cash balance of $50.4 million, equating to approximately 1% of test year electric revenues, is a level that is needed, reasonable, balanced, and adequately minimizes the Company's financial and credit risk.

Q. On page 101 of his direct testimony, Mr. Coppola attempts to discredit the Company's approach to projecting the cash balance for the test year in this case, stating that "cash on hand is not used to pay for revenues. It is used to pay operating expenses, capital expenditures and dividends to the parent company." Is this a valid argument against the Company's 1% of test year revenues rule of thumb?

A. No. The Company's cash estimation method is not intended to project all future cash outflows in order to determine the required cash balance. Rather, the 1% of test year revenues is a simple, efficient, and easily calculated benchmark that is useful in estimating a reasonable level of cash for the Company. As the size of the Company grows along with its associated operating revenues, the appropriate level of cash on hand also grows. Thus, the various uses of the Company's cash is not a valid argument against the Company's cash projection methodology.

Q. On page 101 of his direct testimony, Mr. Coppola again attempts to discredit the Company's approach to projecting the cash balance by stating that "every utility has different short-term borrowing facilities and different practices as to how they use or do not use them and may retain more or less cash on hand depending on those circumstances." Does the fact that different utilities have different practices with respect to short-term borrowing and cash on hand invalidate the Company's 1% of test year revenues rule of thumb?

A. No. Refer to the description of the Company's liquidity and financing strategy on pages 26 to 28 of my direct testimony. The Company's 1% of test year revenues rule of thumb is not intended to match other utilities' liquidity and financing practices. The Company acknowledges that different utilities hold different levels of cash and short-term debt based on their individual preferences and liquidity risk tolerance levels. The Company projects its cash balance at a level that is reasonable and appropriate for Consumers Energy, which equates to approximately 1% of test year revenues.

Q. On page 101 of his direct testimony, Mr. Coppola argues that the Company's cash analysis from Exhibit A-93 (AJD-13) in Case No. U-17990 was inappropriate because it used data on a GAAP financial basis. Does Mr. Coppola perform an analysis based on GAAP financial data in his testimony and exhibits?

A. Yes. Refer to pages 113 to 114 of Mr. Coppola's direct testimony and his Exhibit AG-44 in which he attempts a pro-forma calculation of the Moody's FFO-to-Debt ratio for the Company starting with an equity ratio sourced from Securities and Exchange Commission reported financial statements which are prepared on a GAAP basis. Also refer to Mr. Coppola's peer group equity ratio calculation of 42.2% on his Exhibit AG-38 which,

as explained earlier in my rebuttal testimony, is skewed by using GAAP financial statements. There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. These differences could easily distort the equity ratios calculated in Mr. Coppola's peer group equity ratio analysis. Following Mr. Coppola's own reasoning on page 101 of his direct testimony, his Moody's pro-forma FFO-to-Debt ratio and his peer group equity ratio calculation of 42.2% are misleading and should not be used in determining the appropriate equity ratio for the Company in this case.

Q. On page 102 of his direct testimony, Mr. Coppola references the Commission's Order in Case No. U-21585 (the Company's previous electric rate case) as it relates to the Company's projected cash working capital balance. Has the Commission approved the Company's projected cash working capital balances in recent rate cases?

A. Yes. The Commission approved the Company's projected cash working capital balances (calculated using the 1% of test year revenues rule of thumb) in the prior two electric rate cases (Case Nos. U-21389 and U-21585) as well as the Company's most recent gas rate case (Case No. U-21806). In Case No. U-21585, the Commission found the Company's projected cash balance to be "reasonable and prudent." In that order, the Commission also instructed the Company in its next electric rate case to "provide further and a more specific explanation as to why its approach in determining its working capital cash balance remains appropriate and should continue to be approved." The Company satisfied this requirement on pages 38 to 43 of my direct testimony which describes the key factors and provides evidence that supports the Company's projected test year cash balance of $50.4 million, or approximately 1% of test year electric revenues. Mr. Coppola's proposed disallowance, as

in prior rate cases, should therefore again be rejected by the Commission in this instant case.

Q. On page 102 of his direct testimony, Mr. Coppola recommends that the level of cash in working capital in this case be equal to the average of the actual cash balances for 2022, 2023, and 2024. This equates to a balance of $25.1 million, $25.3 million lower than forecasted by the Company. Do you agree with this proposal?

A. No. Using the average of actual cash balances from 2022, 2023, and 2024 results in a cash balance much lower than is normally expected and required for the Company in the test year of this case. The spike in natural gas prices in 2022 resulted in cash balances that were lower than what is normally expected and required for the Company and are therefore not representative of typical cash balances historically or in the test year of this case. In addition, the Company experienced unfavorable weather in 2023, as well as storm restoration activity well beyond the five-year historical average. Both of these conditions negatively affected the Company's operating cash flows and cash balance. It is inconsistent that Mr. Coppola cites those "temporary" issues when discussing the Company's credit metrics from that period of time but ignores them for this argument. Since the Company's cash balance was abnormally low in 2022 and 2023, the average from those years should not be used in projecting the cash balance in this case. Also, the Company uses a forward looking test year in this case, projecting an adequate level of cash for the test year ending April 2027. Therefore, basing the projected cash balance on current or historical revenues would not be appropriate. Instead, the projected cash balance for the test year in this case should equate to approximately 1% of test year electric revenues,

which results in a cash balance of $50.4 million which is reflective of normal levels of cash on hand.

Q. On page 103 of his direct testimony, Mr. Coppola recommends that the level of cash in working capital in this case be reduced even further by an additional $16.1 million to account for "cash invested in interest bearing securities." Is this a valid argument?

A. No. Mr. Coppola mischaracterizes the $16.1 million as cash investment securities. While the $16.1 million is included in interest bearing operating cash accounts, these are not restricted "cash investments." This cash is unrestricted and available for the Company to draw on at any time. As explained in the Company's response to Mr. Coppola's discovery request U21870-AG-CE-0456, the Company has not included any restricted cash investments in its calculation of working capital for the instant case. Consistent with long-standing ratemaking practice, the cash accounts identified by Mr. Coppola for removal are properly included in the Company's working capital.

Q. On page 103 of his direct testimony, Mr. Coppola claims that acceptance of the Company's projected cash balance in this case would "further expand it cash investing activities to the benefit of the Company and at the expense of customers." Is this an accurate statement?

A. No. Any interest earned on rate base working capital cash balances is included as a reduction to the Company's revenue requirement. Mr. Coppola's claim that the Company is conducting "investing activities" with this cash to the benefit of the Company and at the expense of customers is false and should be rejected by the Commission.

Q. On pages 103 to 104 of his direct testimony, Mr. Coppola again claims that the Company improperly benefits by investing "extra" cash in short-term investments. Do you agree with this claim?

A. No. First, the Company is not projecting "extra" cash in this case but an amount that is reasonable and supportive of the Company's operating, investing, and financing activities. Second, the Company has not included any restricted cash investments in its calculation of working capital for the instant case. Finally, as explained earlier in my rebuttal testimony, any interest earned on rate base working capital cash balances is included as a reduction to the Company's revenue requirement. Mr. Coppola's claims are therefore false and misleading and should not be relied upon in this case.

Q. On pages 104 to 105 of his direct testimony, Mr. Coppola recommends that the Company maintain a low cash balance and rely on its short-term credit facilities to solve any significant liquidity challenges that may arise. Is this a prudent strategy?

A. No. A cash balance of $9.0 million or 0.2% of test year revenues is extremely low for the Company given the size of the business and its operating cash flows. Refer to pages 40 to 41 of my direct testimony in which I explain how the Company's projected cash balance for the test year in this case minimizes liquidity risk. Also refer to pages 42 to 43 of my direct testimony. The Company's cash balance is a component of rating agencies' assessment of credit quality. A low cash balance and relying more heavily on short-term debt as Mr. Coppola recommends is detrimental to the Company's credit quality. In summary, the Company has provided extensive evidence in direct testimony showing that the Company's projection of the working capital cash balance of $50.4 million, equating to approximately 1% of test year electric revenues, is a level that is reasonable, balanced,

and adequately minimizes financial and credit risk. Mr. Coppola's recommended reduction of projected working capital of $44.1 million to $9.0 million is excessively punitive, not supported by the evidence, unduly increases the Company's liquidity risk, and should therefore be rejected by the Commission.

IV. REBUTTAL OF ABATE WITNESS WALTERS

Q. On page 6 of his direct testimony, Mr. Walters presents Table CCW-2 – Trends in State Authorized Common Equity Ratios which lists average equity ratios by year from 2016 to 2025. What trend does the data in this table reveal?

A. As shown in Mr. Walters' Table CCW-2, the average equity ratio has been trending up over the last 10 years. In fact, Mr. Walters' table shows that the average equity ratio for electric utilities covering all years presented is 50.74%, virtually the same as recommended by the Company in this case. In addition, the Company's projected equity ratio of 50.75% is below industry averages for several of the years presented. Mr. Walters' table shows that his recommended equity ratio for the Company in this case of 50% is significantly understated when compared to his own calculation of industry average equity ratios and trends.

Q. Are the average equity ratios reflected in Mr. Walters' Table CCW-2 understated?

A. Yes. According to footnote 1 of Mr. Walters' Table CCW-2, the source of the equity ratio data is "S&P Global Market Intelligence." S&P Global Market Intelligence tracks the authorized equity ratio as a percentage of total capitalization. Total capitalization can be higher (making the equity ratio lower) because, in addition to permanent capital components, items such as short-term debt and customer deposits can be included. As described earlier in my rebuttal of Staff witness Megginson, the Company's proposed

equity ratio in this instant case as a percentage of total capitalization is 42.94%, 781 basis points lower than the 50.75% proposed as a percentage of permanent capitalization. Excluding short-term debt to be consistent with the equity ratio projected by the Company in this case (as a percentage of permanent capital), the order results in a higher equity ratio. Again, in order to make proper comparisons, the Company's equity ratio, based on a percentage of permanent capital, should be compared to utilities also using an equity ratio based on percentage of permanent capital. By utilizing utility equity ratios that are based on a percentage of total capitalization to support his recommended equity ratio for the Company in this case, Mr. Walters is not making a direct like-for-like comparison, and thereby understating his results, which therefore should not be relied upon.

Q. If the equity ratios reflected on Mr. Walters' Table CCW-2 are understated, what is the more appropriate comparison of average utility equity ratios?

A. Refer to my earlier rebuttal testimony to AG witness Coppola in which I explain that actual commission-authorized equity ratios is the preferred data source for an average equity ratio analysis. I refer to my Exhibit A-29 (MRB-10) in which I researched all rate case decisions from 2020 through mid-April 2025 of peer regulated companies and determined the authorized or approved equity ratio for each. Consistent with the Commission's Order in Case No. U-20963, the equity ratios used for comparison purposes were taken from commission orders and public filings and represent actual regulatory peer equity ratios authorized or approved by different commissions across the country. As stated above, the average equity ratio for the peer group was 51.85%. This is significantly higher than the equity ratio of 50.75% projected by the Company and is also 185 basis points higher than the equity ratio Mr. Walters recommends for the Company in this case.

Q. On pages 7 to 8 of his direct testimony, Mr. Walters presents data from S&P Global Market Intelligence which indicates that capital investments by regulated utilities are projected to continue to increase through 2027. Does this trend apply to the Company as well?

A. Yes. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments to maintain and improve utility infrastructure to improve reliability and resiliency to the benefit of customers. During this time, the Company must rely heavily on the capital markets to fund these investments. Therefore, it will be especially important for the Company to maintain strong credit ratings to ensure beneficial access to capital markets for funding to deliver these critical customer investments and enable the Company to do so at the lowest possible financing cost on their behalf.

Q. In addition to the data presented by Mr. Walters on projected utility capital investments, has S&P commented recently on the credit quality of utilities?

A. Yes. As highlighted on page 16 of Mr. Walters' direct testimony, in a January 2025 report on North American regulated utilities, S&P highlighted lower ratings headroom as "a high percentage of companies are operating with only minimal financial cushion from our downgrade threshold." Refer to Exhibit A-40 (MRB-21). S&P also notes that, in 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year. With regard to the industry credit outlook for 2025, S&P identifies risk that will pressure the industry's financial measures, including weak equity ratios, potential new tax legislation, and robust capital spending in challenging regulatory constructs. S&P also sights Michigan as one of the regulatory jurisdictions that they

"continue to carefully monitor." It is apparent from this report that an ROE and equity ratio combination higher than the current authorized level, and certainly higher than the continued degradation proposed by Mr. Walters, is critical to protect the Company from receiving a credit downgrade in light of the credit risks as described above.

Q. Have rating agencies other than S&P also commented on the credit quality of regulated utilities?

A. Yes. As referenced on page 18 of Mr. Walters' direct testimony, Moody's issued a report in which it revised its outlook on the U.S. regulated utilities sector from stable to negative citing "increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and interest rates." In addition, on page 18 of his direct testimony, Mr. Walters references a report by another credit rating agency, Fitch. In describing a "deteriorating outlook for North American utilities, power & gas in 2024," Fitch cited credit headwinds that are putting pressure on utilities' credit metrics. Specifically, Fitch concluded that "the sharp escalation in interest rates has significantly narrowed the headroom in FFO fixed-charge coverage for the sector." It is clear from these reports that rating agencies have recognized a deterioration in credit metrics and credit quality for regulated utilities. These rating agency comments highlight the importance for the Company to maintain strong financial metrics and to not manage toward the perceived low end of the credit metric bands.

Q. On page 22 of his direct testimony, Mr. Walters states that the Company's projected equity ratio of 50.75% is "relatively higher than the equity ratio for the proxy group used to estimate the cost of equity for Consumers Energy." Mr. Walters then references his Exhibit AB-6, which shows a proxy group average equity ratio of 40.1% (including short-term debt) and 43.8% (excluding short-term debt). This is also highlighted on page 30 of Mr. Walters' direct testimony. Are either of Mr. Walters' average equity ratios reflected on Exhibit AB-6 in any way relevant or comparable to the Company's projected equity ratio of 50.75% in this case?

A. No. Refer to my earlier rebuttal testimony to AG witness Coppola's Exhibit AG-38. Like Mr. Coppola's Exhibit AG-38, the average equity ratio calculations for the proxy group on Mr. Walters' Exhibit AB-6 uses the equity ratio at the parent holding company level which may be distorted by other non-regulated balance sheet items and provides a completely inappropriate point of comparison. Mr. Walters' equity ratio analysis is clearly not based on the Commission's regulatory authorization and is therefore not comparable or relevant in determining the appropriate equity ratio for the Company in this case. Further, it is not clear which peer average Mr. Walters recommends to use in determining the appropriate equity ratio for the Company in this case. Earlier in his direct testimony at page 6, Mr. Walters references average state authorized equity ratios in his Table CCW-2 which reflects an average of 50.74% for electric utilities. While the average equity ratios in this table are understated as explained earlier in my rebuttal testimony, they are dramatically higher than the 40.1% and 43.8% reflected on Mr. Walters' Exhibit AB-6. For these reasons, Mr. Walters' comparison of the average equity ratios on his Exhibit AB-6 to the

Company's projected equity ratio of 50.75% is not comparable or relevant and should be disregarded.

Q. On page 23 of his direct testimony, Mr. Walters references the Commission's Order in Case No. U-21585, the Company's last electric rate case, which authorized an evenly balanced equity ratio. Does the equity ratio authorized from a previous rate case necessitate a duplication of that capital structure in this instant case?

A. No. The appropriate equity ratio for the Company should be based on the facts and circumstances presented in this instant case and not predetermined based on prior Commission orders. Refer to my earlier rebuttal testimony to Staff witness Megginson (II.B.ii. Staff Fails to Consider New Circumstances That Justify a Deviation from an Evenly Balanced Capital Structure). While the Commission authorized an evenly balanced capital structure in the case referenced by Mr. Walters, the Commission has also made clear that there should be flexibility in its assessment, allowing for a deviation from an evenly balanced capital structure when circumstances warrant it. It is clear from these orders that the Commission does not consider an evenly balanced capital structure a mandate to be followed blindly, but rather as a basis from which a deviation may be justified upon consideration of the evidence and circumstances of each rate case.

V. REBUTTAL OF CUB WITNESS BANDYK

Q. On page 35 of his direct testimony and his Exhibit CUB-9, Mr. Bandyk calculates an interest coverage ratio for the Company using his recommended ROE and equity ratio as inputs. Mr. Bandyk then references a table from Dr. Damodaran showing interest coverage ratio ranges and the associated credit rating. Mr. Bandyk determines that his calculated interest coverage ratio falls within the range associated with the Company's current credit rating according to Dr. Damodaran's table. Mr. Bandyk then concludes that the Company should be able to maintain its current credit rating, assuming his recommended ROE and equity ratio. Do you agree with this conclusion?

A. No. First, the Company's credit rating is based on several different qualitative and quantitative factors including the regulatory environment, liquidity position, and the Company's business risk profile. Mr. Bandyk's assumption that the results of a single credit metric ratio should have no impact on the Company's credit rating is misguided, as a lower authorized ROE and equity ratio could very well negatively impact these other aspects of the rating agencies' evaluations. Second, while rating agencies track the Company's interest coverage ratio, they place a relatively higher weight on the Company's FFO-to-Debt ratio with respect to potential credit rating actions. The FFO-to-Debt ratio is consistently highlighted in rating agencies' credit opinions and is identified as a factor that could lead to a ratings upgrade or downgrade. I refer to page 15 to 16 of my direct testimony which shows that the Company's FFO-to-Debt ratio has been trending down in recent years. Finally, Dr. Damodaran's table used by Mr. Bandyk in his analysis is compiled with data from all credit rated companies in the U.S. This is an inappropriate

measure, as the credit risk considerations for Consumers Energy, a regulated utility, differ from those of all companies as a whole. The actual range for the Company's interest coverage ratio expected by rating agencies could therefore vary dramatically from Dr. Damodaran's table.

Q. If not Dr. Damodaran's table, what is the appropriate source for the expected interest coverage ratios for the Company?

A. The most relevant source for the expected interest coverage ratios for the Company comes from the credit rating agencies themselves and, more specifically, Consumers Energy's credit reports. These reports take into account all aspects of the Company's risk profile to determine the appropriate expected credit metric ranges.

Q. How do the interest coverage ratios expected by the rating agencies for the Company compare to the interest coverage ratio range determined by Mr. Bandyk based on Dr. Damodaran's table?

A. The actual interest coverage ratio ranges expected by the rating agencies for the Company's current credit rating are significantly higher than Mr. Bandyk calculates. Mr. Bandyk calculates an expected interest coverage range of 3 to 4.2499. Refer to page 5 of Exhibit A-36 (MRB-17) - S&P's August 2024 credit report. The expected FFO cash interest coverage ratio for 2027 is 5.2. The expected EBITDA interest coverage ratio for 2027 is 5.0, both well above Mr. Bandyk's range. Also refer to page 8 of Exhibit A-37 (MRB-18) – Moody's August 2024 credit report. Moody's 12- to 18-month forward view for the interest coverage ratio (CFO pre-WC + Interest / Interest) is 5 to 6, also significantly higher than Mr. Bandyk's range. For the reasons outlined above, Mr. Bandyk's claim that the

Company's credit rating will not suffer as a result of his lower proposed ROE and equity ratio is without merit and should be rejected by the Commission.

Q. On page 37 of his direct testimony, Mr. Bandyk states that the Company did not provide any evidence that the Company is at risk of a credit downgrade from a drop in regulatory environment rankings. Do you agree with this statement?

A. No. Refer to pages 19 to 20 of my direct testimony in which I explain how a component of rating agencies' evaluation of credit quality involves an assessment of the Company's regulatory environment and that the authorized equity ratio and ROE are two important components in that assessment. I presented evidence showing that in 2023 UBS downgraded Michigan's regulatory ranking and in 2024, S&P also lowered its ranking of Michigan's regulatory environment. It should be noted that these regulatory environment downgrades have come at a time when recent rate cases have resulted in a sharp decline in rate of return (equity ratio multiplied by the ROE) following a long period of stability. Contrary to Mr. Bandyk's statement, the Company has shown that rating agencies and analysts are taking note of the Company's regulatory outcomes and are viewing them unfavorably. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating.

Q. On page 37 of his direct testimony, Mr. Bandyk states that "both Moody's and S&P have a 'stable' outlook for Consumers Energy, meaning they see little risk of a downgrade." Does a stable outlook necessarily indicate little risk of a downgrade in the future?

A. No. Refer to my earlier rebuttal testimony to Staff witness Megginson on this matter. In assessing credit quality, rating agencies must make certain assumptions with respect to the Company's outlook, including future financial results and regulatory outcomes. However, a stable outlook should not be interpreted as assurance that these assumptions will ultimately materialize, with no risk of a credit rating downgrade. For example, in June 2019, Moody's issued a credit opinion for the Company stating that "Consumers' stable outlook reflects our expectation that the Michigan legislative and regulatory environments will remain constructive." Moody's also stated that they expected the Company's FFO-to-Debt ratio to "range between 20% and 24% over the next few years." In May 2021, Moody's downgraded Consumers Energy's credit rating "due to its weakened credit metrics." Moody's also referenced the outcome of recent rate cases which put pressure on the Company's credit metrics. While rating agencies may assume that the Company will continue to operate in a constructive regulatory environment with credit metrics above the downgrade threshold, the Company's credit rating is continuously evaluated. A reduction in the Company's rate of return lowers cash flow, increases debt, and thereby weakens the Company's FFO-to-Debt ratio. These negative credit metric impacts place the Company's credit quality and credit ratings at risk. The authorized ROE and equity ratio in this case will be a key component of future rating agency evaluations.

Q. On page 38 of his direct testimony, Mr. Bandyk references a discovery response in which the Company did not identify a specific FFO-to-Debt ratio that would trigger a credit downgrade. Does this response invalidate the evidence presented in direct testimony which justifies the Company's recommended ROE and equity ratio?

A. No. As explained in the referenced discovery response, rating agencies have FFO-to-Debt ranges that they expect the Company to maintain based on its current risk category / credit rating. While continued underperformance may lead to a ratings downgrade, there is no specific FFO-to-Debt identified that would automatically trigger a negative credit rating action. As explained earlier in my rebuttal testimony, the Company's FFO-to-Debt metric is one of several qualitative and quantitative measurements that rating agencies consider before taking action on a credit rating. A reduction in authorized ROE combined with a lower equity ratio can lead to a deterioration of credit metrics and ultimately a downgrade. This reasoning was validated by Moody's 2021 credit rating downgrade, which specifically pointed to these issues and their associated negative credit metric impacts.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Thank you, Your Honor.

Next is the direct testimony of Eugene M Breuring, which consists of a cover page and 21 pages of questions and answers, Mr. Breuring also had rebuttal testimony consisting of a cover page and 11 pages of questions and answers. Mr. Breuring also had Exhibit A-5 Schedule E-1 and Exhibit A-15 schedules E-1 through E-4 and Exhibit A-52.

THE COURT: Am I correct that there are other schedules for Exhibits A-5 and A-15?

MR. GENSCH: I believe Mr. Breuring is the only one with schedules for those exhibits. Checking my list. He's the only one I see, Your Honor.

THE COURT: So, schedule E-1 is -- is the only schedule for Exhibit A-5, correct?

MR. GENSCH: Correct.

THE COURT: And similarly, Schedule E-1 through E-4 are the only schedules for Exhibit A-15?

MR. GENSCH: Yes, Your Honor.

THE COURT: All right. Are there any objections to the admission of this test or these exhibits?

Hearing none, the direct and rebuttal testimony of Eugene Breuring is bound into the record and Exhibits A-5, A-15, and A-52 are admitted.

(At 2:43 p.m., Exhibits A-5, A-15, and A-52 admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Eugène M.J.A. Breuring, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Sales Forecasting Analyst in Financial Planning & Analysis.

Q. Please describe your qualifications.

A. In 1992, I graduated from Grand Valley State University with a Bachelor of Business Administration in Accounting. In 1996, I graduated from Thunderbird School of Global Management with a Master of Business Administration in International Management. I have also attended trade-specific conferences and seminars related to Michigan and United States economies, Michigan economic forecasts, as well as regression modeling.

Prior to joining Consumers Energy in 2013, I worked at the Kellogg Company, Tecumseh Products Company, and Stryker Corporation, mostly in a financial planning, budgeting, and forecasting capacity. In January 2013, I accepted the position of Senior Rate Analyst II. In 2020, I was promoted to Senior Analyst III, and again in 2023 to Principal Sales Forecasting Analyst, which is my current position at Consumers Energy. In this capacity, I am responsible for preparing the Company's official electric deliveries and customer forecasts, sponsoring the deliveries and customer forecast testimony and exhibits, industry research, and various economic studies. Also, I am responsible for creating the Company's revenue forecast related to the electric business.

Q. Have you sponsored testimony in any previous cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have presented the Company's electric business sales and revenues forecasts in the following cases:

U-17771	2016 – 2017 Energy Optimization Plan;
U-17990	General Electric Rate Case;
U-18142	2017 Power Supply Cost Recovery ("PSCR") Plan;
U-18231	2017 Biennial Renewable Energy Plan;
U-18261	Amended Energy Optimization Plan;
U-18322	General Electric Rate Case;
U-18402	2018 PSCR Plan;
U-20134	General Electric Rate Case;
U-20165	2018 Integrated Resource Plan ("IRP");
U-20219	2019 PSCR Plan;
U-20372	2019 Energy Waste Reduction ("EWR") Electric and Gas Plan;
U-20525	2020 PSCR Plan;
U-20697	General Electric Rate Case;
U-20802	2021 PSCR Plan;
U-20875	2022-2025 EWR Plan;
U-20963	General Electric Rate Case;
U-21048	2022 PSCR Plan;
U-21090	2021 IRP;
U-21257	2023 PSCR Plan;

U-21321	2024-2025 EWR Plan;
U-21389	General Electric Rate Case;
U-21423	2024 PSCR Plan;
U-21585	General Electric Rate Case;
U-21592	2025 PSCR Plan;
U-21680	2025 EWR Plan; and
U-21816	Amended RE Plan.

Furthermore, I have been involved in preparing the forecasts sponsored by other Company witnesses in prior cases before the MPSC.

Q. Please explain the purpose of your direct testimony in this proceeding.

A. The purpose of my direct testimony is to present the Company's electric revenues, deliveries, generation requirements, and peak demands for the split-test year May 2026 – April 2027.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following exhibits:

Exhibit A-5 (EMB-1)	Schedule E-1	Annual Service Area Calendar Sales by Major Customer Classes and System Output – 5-Year Historical;
Exhibit A-15 (EMB-2)	Schedule E-1	Annual Service Area Calendar Sales by Major Customer Classes and System Output – 5-Year Projected;
Exhibit A-15 (EMB-3)	Schedule E-2	Test Year Total Company Electric Revenues & Deliveries;
Exhibit A-15 (EMB-4)	Schedule E-3	Electric Deliveries & Customer Counts by Rate Category;
Exhibit A-15 (EMB-5)	Schedule E-4	Calculation of Annual System Load Factor; and

Exhibit A-52 (EMB-6)	Estimated Electric Rate Case PSCR Factor.

Q. Were these exhibits prepared by you or under your direct supervision?

A. Yes.

SECTION I. FORECASTING METHODOLOGY

Q. What is forecasting?

A. Forecasting is predicting the future values of data. For purposes of this direct testimony, the Company will forecast electric deliveries and peak demand for the Company's electric service territory.

Q. Are there different types of analyses used in preparing forecasts?

A. Yes.

Q. What type of analysis was utilized for forecasting electric deliveries and peak demand for the Company's electric service territory?

A. Statistical modeling, or a regression analysis, was used to forecast electric deliveries and peak demand for the Company's electric service territory.

Q. Please briefly describe the process used to prepare the electric deliveries and peak demand forecasts.

A. The electric deliveries and peak demand forecasts are prepared using a combination of econometric and end-use techniques.

Q. What process is involved in developing the electric deliveries forecast?

A. Typically, a six-step process is used in developing the electric deliveries forecast. The first step in the process is gathering the class-level historical monthly electric delivery, monthly customer counts, monthly number of billing days, monthly binaries to account for seasonal variation, and daily temperature information. Most observations are entered directly into

the modeling framework as dependent and explanatory variables. The daily temperature information, however, is transformed to monthly heating degree days ("HDD") and cooling degree days ("CDD") variables prior to entering the modeling framework. The second step is importing the economic and demographic variables from S&P Global (formerly, IHS Markit) into the sales modeling framework. These variables cover historical data going back to 2001, the start of the time horizon within the regression modeling process, as well as projections to the test year. The third step is importing electric use forecasts for wholesale, electric vehicles, polycrystalline production, Distributed Generation ("DG"), and energy savings from the Company's EWR programs. These forecasts are exogenous to the modeling framework and were either adopted by the Commission in prior electric rate cases, reflect current industry expectations, or are based on end-use analyses. The fourth step is reviewing the imported observations to identify data issues before running the econometric models. In situations when erroneous data is observed, it is either corrected where possible or removed from the models. The fifth step is executing the regression functions and reviewing the corresponding statistical metrics. The final step in the sales forecasting process is to combine the regression forecasts with the external forecasts imported in step three.

Q. What is the process involved in developing the electric peak demand forecast?

A. The peak demand forecast process is like that of the electric delivery forecast. The first step in the peak demand forecast is importing the Company's monthly system peak demands, corresponding minimum and maximum daily temperature, forecasted base electric deliveries, seasonal binaries, and number of customers into the demand modeling framework. An average of the minimum and maximum temperatures is used to develop

the peak CDD and HDD variables before these variables are imported into the model framework. The second step is reviewing the imported observations to identify data issues before executing the peak demand econometric model. The third step is regressing the observed peak demands against the seasonal binary, degree day, and forecasted base electric sales.

The final step in the peak demand forecasting process is combining the results of the econometric model with the Company's projected peak demand adjustments, which consists of the following: (1) EWR; (2) Dynamic Peak Pricing ("DPP") programs; (3) Conservation Voltage Reduction ("CVR"); and (4) Residential Summer On-Peak rate ("RSP").

Q. In utilizing the regression models, what evaluation process is followed to ensure that the models' results are satisfactory?

A. Regression modeling is used to develop the electric deliveries and customer count forecast models based on weather and economic variables. Each model is selected based on its ability to properly explain variation in historical data – i.e., how well it fits the data – along with the statistical significance of the model coefficients. Particularly, regression model performance is evaluated based on the adjusted coefficient of multiple determination ("R_a^2") and Mean Absolute Percent Error ("MAPE").

Q. Please explain the use of R_a^2 and MAPE.

A. Both statistical tests are used to evaluate how well the models fit the historical data and provide a good indication of how well the models will perform in the forecast period. The R_a^2 measures the ability of the models to explain variations in the historical data. An R_a^2 of unity suggests that a model explains all the variations in the data whereas an R_a^2 of zero

suggests it explains none of the variations. For example, if regression models have R_a^2 values above 0.9, this suggests that at least 90% of the variation in the data is explained by the models. In most cases, the models used in the Company's forecasting process have values between 0.90 and 0.97. In addition, to gauge overall model performance, the MAPE values are considered. Essentially, MAPE is used to measure the model errors in which smaller values suggest better model performance. MAPE values of less than 3% are generally considered ideal, although higher values may also be deemed acceptable based on other considerations, such as the R_a^2. The regression models used in the Company's forecasting process generally have MAPE values between 0.2% and 2.1%.

Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.

A. Regression analysis is used to develop models that minimize the variance between the actual data and estimates from the models based on the relationship between dependent and independent variables. A numerical coefficient ("β") is estimated for each independent variable in the model and represents the best linear unbiased estimate for that variable's contribution toward explaining the dependent variable. The t-statistics and p-values are used to gauge the relevance of each independent variable in the model. The t-statistic and p-values measure the statistical significance of including a particular independent variable based on a probability distribution. A t-statistic above two and p-value below 5% for a particular β suggests the independent variable is statistically significant and is appropriate to include in the regression model. Independent variables with t-statistics below two and p-values above 5% suggest the variable should be excluded from the model since it does little to explain the dependent variable. In addition, the

direction (positive or negative coefficient sign) and magnitude of each coefficient are also considered when determining to include or exclude variables from the models. The models' independent variable t-statistics and p-values are within the statistically significant ranges described above and are, therefore, considered relevant.

Q. What software is used to create these regression models for the energy, demand, and customer count projections? And why?

A. For at least the last 15 years, the Company has utilized MetrixND for its regression modeling. MetrixND is a software package that is licensed by Itron, Ltd., a global technology company that provides technology and professional services to utilities to aid in their sales forecasting needs. Furthermore, MetrixND is considered an industry standard, as more than 150 utilities, Independent System Operators, municipals, cooperatives and other energy service providers use Itron's MetrixND.[1]

SECTION II. KEY ELECTRIC DELIVERY AND DEMAND VARIABLES

Q. What are the key variables that affect the electric deliveries and demand forecasts?

A. The key variables affecting the forecasts are weather, the economy, and demographics, as well as variables related to EWR, DG, Electric Vehicles ("EVs"), and COVID-19, a variable to capture the impact of the COVID-19 pandemic.

Q. Please describe the impact of weather on the forecasting process and the assumptions you made regarding weather variables in the forecast.

A. Weather is the primary variable used in the forecasting models to capture the seasonal variation in deliveries and demand across the year. This is accomplished using a 15-year average of Heating Degree Days-60 ("HDD60") and Cooling Degree Days-60 ("CDD60")

[1] https://na.itron.com/o/commerce-media/accounts/-1/attachments/3828543.

in the econometric models. The HDD60 variable captures historical temperatures warmer than 60 degrees Fahrenheit. The CDD60 variable captures historical temperatures cooler than 60 degrees Fahrenheit.

Q. What are econometrics or econometric techniques?

A. These are quantitative economic statistical techniques or tools that model the economy using mathematical and statistical relationships. A basic tool for econometrics is the regression model, as discussed elsewhere in my testimony.

Q. Please describe the impact of the economy on the forecasting process and the assumptions you made regarding these variables in the forecast.

A. The Company uses economic indicators to capture the growth expectations related to increased economic activity in its service territory. Primarily, this includes employment and industrial production forecasts provided by S&P Global, a leading publishing company that provides industry-specific data and analyses.

Q. Please describe the impact of demographics on the forecasting process.

A. Population projections are used in the development of the long-term customer forecast. In particular, the forecast of commercial customers is derived from the county-level population projections provided by S&P Global.

SECTION III. TEST YEAR ELECTRIC REVENUES

Q. Please describe Exhibit A-15 (EMB-3), Schedule E-2.

A. Exhibit A-15 (EMB-3), Schedule E-2, is a single-page exhibit that summarizes the component differences between the 2024 historical revenues and deliveries and the forecasted test year revenues and deliveries used in this case.

Q. Please explain the Weather-Normalization column, column (f), in Exhibit A-15 (EMB-3), Schedule E-2.

A. Exhibit A-15 (EMB-3), Schedule E-2, represents a "walk" from the 2024 historical year to the projected test year. The historical year represents actual revenues and deliveries, which are not weather-normalized. Since the Company's projections are weather-normalized, column (f) represents the 2024 impact of weather-normalizing the historical actuals.

Q. Please explain the Pro Forma column, column (h), in Exhibit A-15 (EMB-3), Schedule E-2.

A. The Pro Forma column in this exhibit represents the difference in revenues due to the difference in rates between the historical year 2024 and the projected test year. 2024 revenues were based on customer rates established by the Commission's March 1, 2024, Order in Case No. U-21389 ("Case No. U-21389 Order"), while the test year revenues are projected revenues based on the rates established by the Commission's March 21, 2025 Order in Case No. U-21585 ("Case No. U-21585 Order").

Q. Please explain the Long-Term Industrial Load Retention Rate ("LTILRR") and Large Economic Development Rate ("LEDR") adjustment, shown in column (e), to deliveries (MWh) and revenues in Exhibit A-15 (EMB-3), Schedule E-2.

A. The LTILRR and LEDR are specialized industrial rates. The LTILRR was approved by the Commission in its Case No. U-20697 Order to allow customized electric rates (LTILRR) for customers meeting certain criteria. The LEDR was approved by the Commission in its Case No. U-21160 Order. As such, the Company has excluded revenues and deliveries of certain large industrial customers that receive service under the LTILRR and LEDR from base tariff revenues, as well as deliveries in the test year. Instead, these

projected test year revenues are reflected in the Miscellaneous Revenues line in Exhibit A-15 (EMB-3), Schedule E-2, column (e), line 24. Company witness Laura M. Connolly supports the details behind these LTILRR/LEDR projected revenues and deliveries.

Q. Please explain the credit revenues that are included in the test year projections as they relate to the Residential Senior Citizen ("RSC") and Residential Income-Assistance ("RIA") provisions.

A. The average test year customer count projections for the RSC and RIA provisions are 380,928 and 63,282, respectively. In the test year, these projected customer counts generate revenue credits of $18.3 million (380,928 customers x $4 credit x 12 months) for the RSC provision and $7.6 million for the RIA provision (63,282 RIA customers x $8 credit x 12 months = $6.1 million plus 4,200 Low-Income Assistance Credit ("LIAC") customers x $30 credit x 12 months = $1.5 million). Included in the RIA credit revenues is a $30/meter LIAC for 4,200 low-income customers, as approved by the Commission's Case No. U-20697 Order.

The associating reduction in base tariff revenues is embedded in Exhibit A-15 (EMB-3), Schedule E-2, column (j), line 1.

SECTION IV. HISTORICAL AND FORECASTED ELECTRIC DELIVERIES

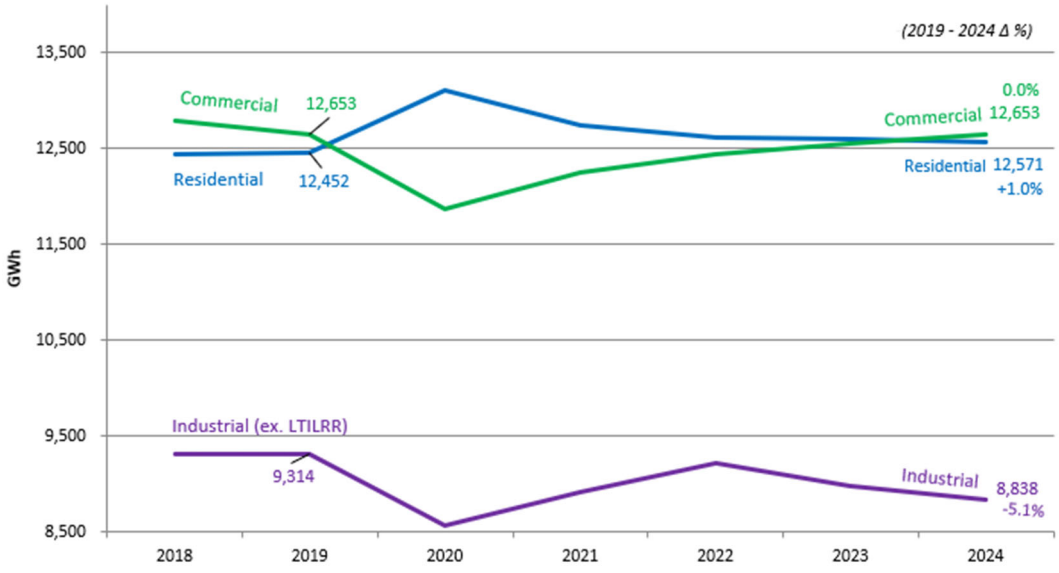
Q. In the Order of Case No. U-21585, the Commission directed the Company to provide both historical and forecasted sales on both a cycle-billed and calendar basis and provide the 60-months of most recent actual historical, weather-normalized historical, and projected sales in the same level of granularity. Has this been provided?

A. Yes. In Part III, attachments 014, 015, and 016, both historical and forecasted data are shown by calendar and cycle-billed, by class and on a monthly basis for 60 months.

Q. Please explain the Company's historical levels of electric deliveries for the period from 2019 (pre-pandemic) to the historical year 2024.

A. In the years since 2019 (pre-pandemic), weather-normalized electric deliveries have remained virtually flat at a -0.1% decrease versus 2024 (the historical year), with the industrial class changing -5.1%, and the commercial class changing 0.0%. The residential class showed an increase of 1.0% during this period. These changes are graphically depicted in Figure 1.

Figure 1 Historical Electric Calendar, Weather-adjusted Deliveries by Class



Q. What is the cause of the sudden Residential increase and Commercial/Industrial ("C&I") decrease of the 2020 weather-normalized deliveries, as shown in Figure 1?

A. Following 2019, the Company's deliveries were impacted by the COVID-19 virus and the resulting pandemic. In 2020, the pandemic caused significant customer behavioral changes, such as an increase in remote working and temporary cessations or reductions in in-person operations for some C&I customers.

Q. How did COVID-19 impact the different customer classes?

A. COVID-19 and the ensuing pandemic had an inverse effect on the Company's residential and C&I customer classes. In 2020, the residential deliveries increased 5.2% over 2019 on a weather-adjusted basis. Conversely, weather-adjusted C&I (excl. LTILRR) deliveries decreased by 6.2% and 8.0%, respectively.

Q. Have the customer classes returned to their pre-pandemic levels by the historical year 2023?

A. Generally, each customer class has returned to a "post-pandemic" trend. Meaning, these classes have mostly recovered from the significant impact the pandemic had on their individual trends (residential class up, commercial flat, and industrial class down). When looking at Figure 1 above, the residential class remains 1% above pre-pandemic levels (after its steep increase of 5.2% in 2020), which can be attributed to the fact that the "working remotely" paradigm has shifted to where some employees are still working remotely part of the time. The C&I classes remain near or below pre-pandemic levels by 0.0% and 5.1%, respectively (after respective declines of 6.2% and 8.0% in 2020).

Q. What are the electric delivery expectations for the test year used in this case?

A. Test year deliveries are projected at 38,662 GWh, as shown in Exhibit A-15 (EMB-2), Schedule E-1, which is an approximate two-year compound annual growth rate ("CAGR") of +2.5% over the weather-normalized historical year 2024 of 36,776 GWh, as shown in Exhibit A-5 (EMB-1), Schedule E-1, page 2. However, 3.6% of this growth is attributable to LTILRR/LED. Excluding LTILRR/LED, the two-year CAGR is -1.1%.

Q. Please explain Exhibit A-15 (EMB-4), Schedule E-3.

A. Exhibit A-15 (EMB-4), Schedule E-3, is a one-page exhibit that shows annual deliveries and customer counts by rate category from the historical year to the test year. The historical year (2024) figures are aligned with numbers as reported to the MPSC (Form P-521) and the deliveries are not weather-adjusted.

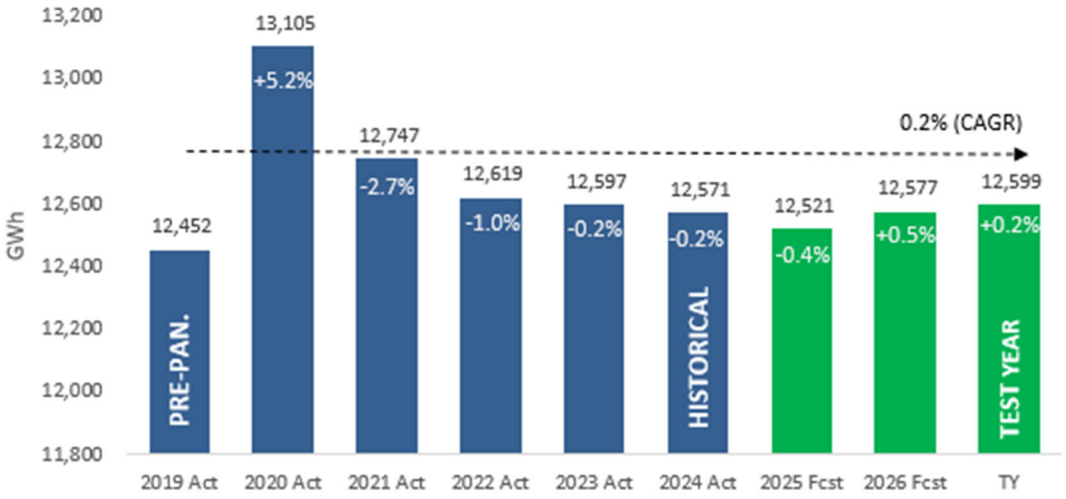
Q. Please explain the significant decrease in deliveries from the historical year to the test year in this exhibit.

A. The main driver of change in deliveries between the historical year and the test year is related to LTILRR volumes (represented in Primary Demand GPD), which are excluded in the test year, but have not been removed from the historical period. Also excluded from the test year are deliveries related to Grand Rapids ("GR") Streetlighting, which is considered non-jurisdictional. Same as the last rate case, GR test year volumes and revenues are categorized as miscellaneous. Its deliveries (MWh) are excluded from the test year, while its revenues are included in miscellaneous revenues (see Exhibit A-15 ("EMB-3"), Schedule E-2, column (d), line 24. Finally, the single wholesale customer (non-jurisdictional) has ceased its contract with the Company as of the end of 2024. Therefore, no wholesale deliveries are shown in the test year.

Q. What do the historical and projected deliveries look like in the residential customer class?

A. The residential customer class is projected to grow at a 0.2% CAGR from 2019 (pre-pandemic) to the test year. As can be seen from Figure 2 below, the residential class increased significantly in 2020 due to, among other things, many people working from home (+5.2%, year-over-year). 2021 was seen as a correction with deliveries reducing by 2.7% as some workers returned to in-person work at an office location. As a result of this reversion to pre-pandemic behavior regarding work locations, residential deliveries are projected to continue to level out toward the test year.

Figure 2

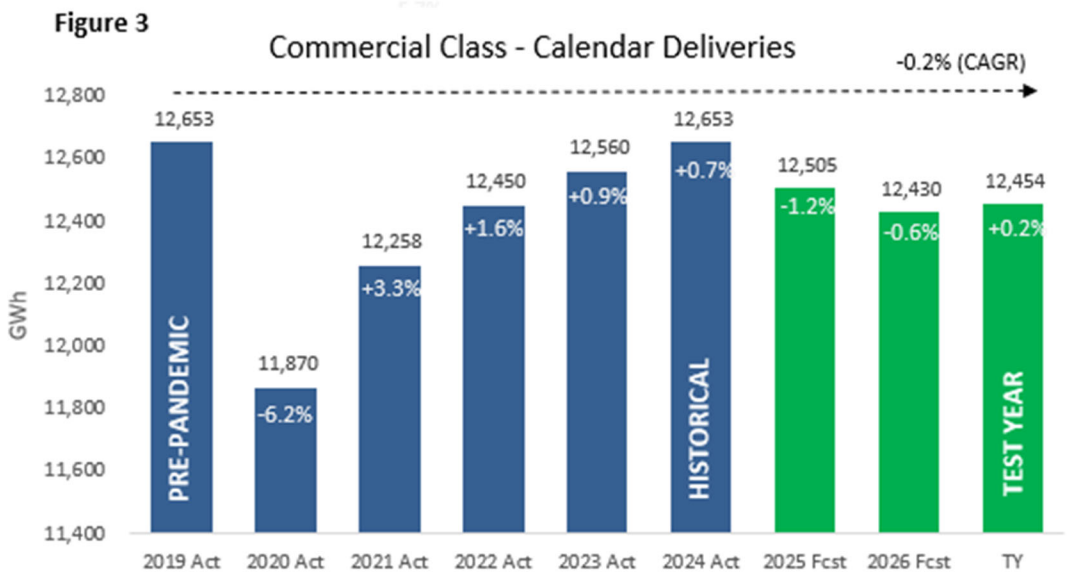


Q. What do the historical and projected deliveries look like in the commercial customer class?

A. The commercial customer class is projected to recede by a -0.2% CAGR from 2019 (pre-pandemic) to the test year. As can be seen from Figure 3, the commercial class decreased significantly in 2020 due to the negative impact the pandemic had on retail, schools, restaurants, and other commercial customers (-6.2%, year-over-year). 2021

marked an improvement for these commercial sectors, which is reflected by the 3.3% year-over-year increase in deliveries. Commercial deliveries are projected to level out toward the test year, though total deliveries in the test year are still below the pre-pandemic year of 2019 by a -0.2% CAGR.

Figure 3



Q. What causes the reduction in projected deliveries in the commercial class?

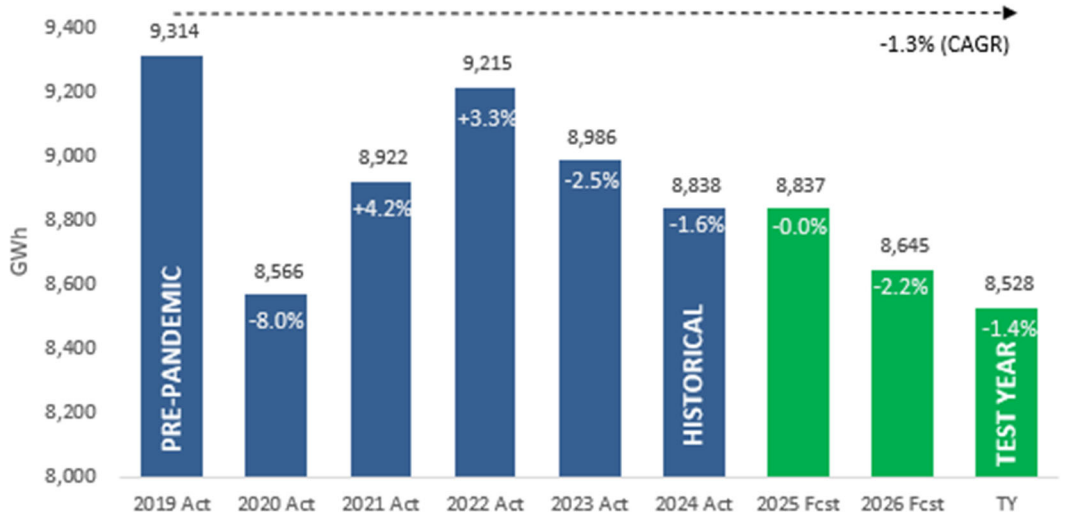
A. The majority of the reduction is due to increased levels of EWR from the historical year to the test year. Please refer to page 18 for more details around EWR savings by customer class.

Q. What do the historical and projected deliveries look like in the industrial customer class?

A. The industrial class is projected to recede by a -1.3% CAGR from pre-pandemic to the test year. Initially, in 2020, the industrial class was impacted more drastically than the other classes, as the class decreased by 8.0% year-over-year. See Figure 4. However, two years

later, in 2022, this class regained most of lost sales since the pandemic. From the historical year to the test year, EWR pressures push the deliveries down.

Figure 4 Industrial (Ex. LTILRR/LED) Class - Calendar Deliveries



Q. Does the test year delivery forecast anticipate an increase in EVs in the Company's service territory?

A. Yes, the Company is expecting the number of EVs in its service territory to grow from 39,950 in 2024 to an estimated 122,989 EVs by the test year, which is a 68% CAGR. These 122,989 EVs will add incremental annual electric load of approximately 480 GWh.

Q. Is the increased load due to EVs concentrated only around the residential customer class?

A. No, of the total anticipated incremental EV load of 480 GWh in the test year, 314 GWh (65%) is expected to be residential load. The other 166 GWh (35%) is allocated to the business sector.

More details related to EVs is covered by Company witness Jeffrey A. Myrom.

Q. Does the test year delivery forecast include any impact due to DG?

A. Yes. DG remains a relatively small piece of the total deliveries in the test year. DG is expected to increase at a faster growth rate than historical levels. In 2025, DG is expected to reduce residential deliveries by 37 GWh, or 0.30% of total residential load. For the test year, DG is projected to increase to 44 GWh, or 0.35% of total residential load.

Q. To what extent has the Company reflected future EWR in the electric deliveries forecast you are sponsoring in this case?

A. The Company was required under the 2008 Energy Law, Public Act 295, to help its electric customers reduce their energy usage by at least 1% per year. In 2016, State lawmakers reinforced the use of demand-side resources, such as EWR, by amending the law to encourage utilities to expand the use of demand-side resources beyond the mandated floors. The Governor signed the 2016 Energy Laws, Public Acts 341 and 342, on December 21, 2016. Most recently, in 2023, the Michigan Legislature and Governor again amended the law to include a 1.5% EWR mandate for electric utilities beginning in 2026 and a 2% EWR goal. This change was enacted through Public Act 229 of 2023, which took effect on February 13, 2024. The Company was already on a path to meeting this 1.5% EWR mandate long before the Legislature and the Governor increased the mandate. Since 2017, the Company's electric deliveries forecast factored in its commitment to help customers reduce energy waste by at least 1.5% per year.

Q. What level of EWR savings is included in the test year deliveries?

A. From 2024 to the test year, the Company is expected to grow EWR savings to 1.9%, as filed in the Company's latest IRP proceeding, Case No. U-21090. At the test year, the

Company's projected EWR savings are 1.7%, with the residential class being projected at 1.1% and the business class (C&I) is projected at savings of around 1.8%.

Q. Please describe the process used to determine the Company's total generation requirements.

A. The forecasted total electric deliveries are increased by a line loss factor as determined by the 2023 System Loss Study to arrive at the Company's total generation requirements, i.e. system output, shown in Exhibit A-15 (EMB-2), Schedule E-1, and Exhibit A-15 (EMB-5), Schedule E-4.

Q. Is the 2023 System Loss Study the latest available?

A. The 2023 System Loss Study was the latest available at the time the test-year projections were created for this case.

Q. Please explain Exhibit A-52 (EMB-6).

A. Exhibit A-52 (EMB-6) calculates the projected test year PSCR Factor based on the electric deliveries and power supply expenses used in this case.

SECTION V. FORECASTED PEAK DEMAND

Q. What are the expectations for growth in peak demand?

A. The Company uses regression analysis based on the predicted level of electric deliveries to forecast the peak demand. Weather-normal peak demand grew at a 1.6% CAGR from 2003 to 2007 but reversed much of this trend during the 2007 to 2009 recession. Looking forward, peak demand is expected to increase 0.5% per year from 2024 to 2029. The monthly system level results of the electric peak demand forecast process is shown in Exhibit A-15 (EMB-5), Schedule E-4.

Q. What is the impact to the peak demand forecast from the Company's Smart Energy programs?

A. The peak demand forecast is reduced by approximately 34 MW in 2025 to 40 MW in 2029 for the Company's DPP programs, which consist of Peak Time Rewards and Critical Peak Pricing.

Q. Are there any other adjustments to peak demand?

A. Yes. In 2025, EWR and CVR measures are estimated to reduce peak demand by 869 MW and 62 MW, respectively. This cumulative reduction to peak demand is projected to increase to 1004 MW (EWR) and 87 MW (CVR) in the test year.

Q. Are capacity-side demand response ("DR") resources accounted for in the Company's peak demand forecast?

A. No. Capacity-side DR resources, such as Residential AC Peak Cycling and C&I DR, which includes Rate GI and Rate EIP, are registered with Midcontinent Independent System Operator, Inc. and are accounted for outside of this peak demand forecast. Company witness Megan L. Metz supports the capacity-side DR in her testimony.

Q. To what extent is the Company's RSP rate expected to impact peak demand?

A. Rate RSP is expected to reduce the Company's peak demand by approximately 66 MW in the test year.

Q. What process is used to identify the peak demand impacts of the Company's EWR programs?

A. The Company developed hourly load profiles for the EWR programs. The monthly energy savings associated with each of these programs are integrated with the corresponding load shape to develop hourly demand savings curves.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Eugène M.J.A. Breuring and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Sales Forecast Analyst in Sales Forecasting in the Financial Planning & Analysis Department.

Q. Are you the same Eugène M.J.A. Breuring who previously filed direct testimony in Case No. U-21870 on behalf of Consumers Energy?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal is to provide rebuttal to the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Paul R. Ausum.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

REBUTTAL OF STAFF WITNESS AUSUM

Q. In the direct testimony of Staff witness Ausum, page 5, lines 4 through 10, he recommends an increased deliveries adjustment of 204,656 MWh for bundled service and 16,308 MWh for choice service. This represents about 1.8% of the commercial forecast for the test year load. Do you agree with this adjustment?

A. No. I do not believe an increase in projected commercial test-year deliveries is warranted.

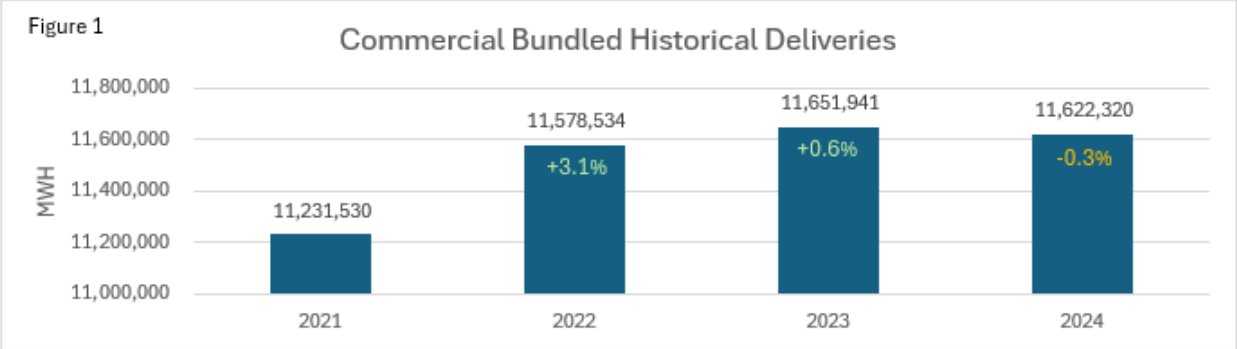
Q. Why don't you agree with Staff witness Ausum's suggested increase to the commercial forecast?

A. There are numerous reasons why I disagree with the suggested increase in the commercial load forecast, such as historical trends, limited analysis, and regression model limitations.

Q. Could you elaborate on the historical trends of the commercial bundled class and how they compare to those considered in Staff's forecasting process?

A. Since 2020, the commercial bundled class has been undergoing a recovery from the impacts of the COVID-19 pandemic. While electric consumption initially rebounded, growing by 3.1% in 2022, it began to stabilize in 2023 with a modest increase of 0.6%, and then declined slightly by 0.3% in 2024.[1] These figures reflect a return to more normalized consumption patterns, and this trend is illustrated in Figure 1.

Figure 1



Q. What is the cause of the normalizing trend, shown in Figure 1?

A. As previously noted, the initial surge in commercial electric deliveries following the pandemic has gradually normalized. This normalization is primarily driven by persistent downward pressure from Energy Waste Reduction ("EWR") initiatives, which reduce

[1] Part III, att 015, cycle-billed deliveries.

deliveries by approximately 1.8%[2] annually. While growth factors such as economic activity, increases in customer count, and electric vehicle ("EV") adoption provide some upward momentum, each of their impacts have been modest. Historical delivery growth remains marginal, reflected in a compound annual growth rate ("CAGR") of just +0.2%[3] from 2022 to 2024. In essence, the declining trend is the result of sustained EWR savings that are not sufficiently counterbalanced by other growth drivers to produce meaningful net growth.

Q. How does Staff's suggested increase in commercial bundled deliveries stack up against recent historical delivery trends?

A. Incorporating Staff's proposed increase in commercial bundled deliveries results in a projected two-year CAGR of 1.0% for the test year. In contrast, the Company's forecast reflects a more modest two-year CAGR of 0.1%, which is in line with the two-year historical CAGR of +0.2%. This disparity highlights a significant deviation from recent historical trends, as illustrated in the tables below and Figure 2.

Consumers Energy Projection (original)

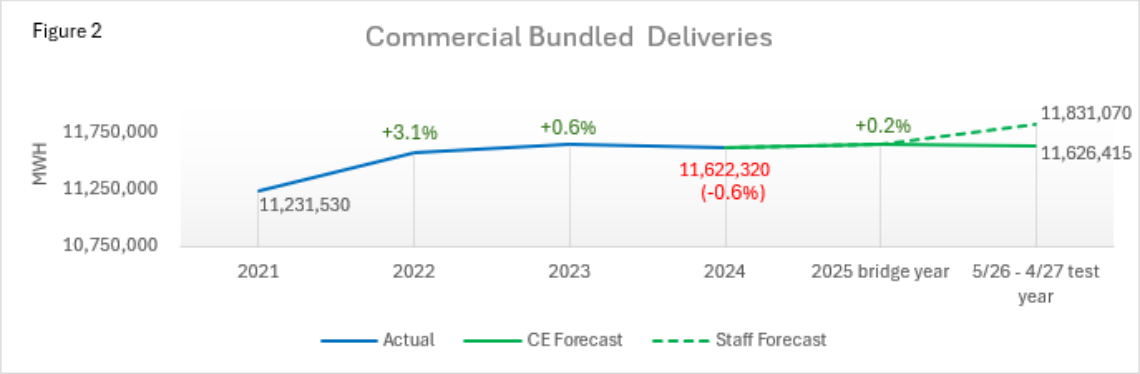
	Year	MWh	CAGR
act/fcst	2024/2025	11,597,766	
test yr.	2026/2027	**11,626,415**	**0.1%**

MPSC Staff Projection (suggested)

	Year	MWh	CAGR
act/fcst	2024/2025	11,597,766	
test yr.	2026/2027	**11,831,071**	**1.0%**

[2] Direct testimony, Company witness Breuring, page 18, lines 20-22 to page 19, lines 1-2.
[3] 2022: 11,578,534 MWh; 2024: 11,622,320 MWh. CAGR: (11,622,320/11,578,534) ^(1/2)-1 = 0.2%

Figure 2



Achieving a 1.0% annual growth rate by the test year, as Staff witness Ausum suggests, represents a significant departure from recent historical delivery trends, as shown in Figure 1. Such growth would only be plausible under conditions of substantial expansion in EV adoption, economic activity, commercial customer counts, or a combination thereof.

Q. Aren't we experiencing higher growth in EVs in the Commercial sector?

A. Yes, however, that growth (+0.47% CAGR)[4] has already been incorporated into the Company's test year forecast. Therefore, it is highly improbable that the EV projections—provided by Company witness Jeffrey A. Myrom—are understated by as much as 24%, or an incremental 152,000 vehicles.[5]

Q. If the EV count is not contributing to Staff's suggested incremental growth, can the economy in the Company's service territory facilitate the proposed growth in commercial deliveries?

A. Unlikely. As outlined in my direct testimony,[6] the primary growth drivers in the regression models are key economic indicators sourced from S&P Global, a reputable provider of industry-specific forecast data tailored to the Company's service territory.

[4] Based on EV count established in current forecast: 43,519 EVs (April 2025) to 122,989 EVs (end of test year).
[5] Based on my calculations, all else being equal, an additional 152,000 electric vehicles in Consumers Energy's service territory by the end of the test year would result in approximately 204,656 MWh of increased electric deliveries, the suggested increase by Staff witness Ausum.
[6] Direct testimony, Company witness Breuring, page 5, lines 3-7 and page 9, lines 14-17.

Upon reviewing the indicators used in both the Company's regression model (service employment) and Staff's model (non-manufacturing employment), the two-year CAGRs leading up to the end of the test year are just 0.1% and 0.17%, respectively.[7] These modest growth rates do not support the level of commercial delivery increase proposed by Staff.

Q. If not EV growth, nor economic expansion, how about growth in customer counts in the commercial sector? Can that support Staff's suggested commercial delivery growth?

A. No. The two-year CAGR for bundled commercial customer count leading up to the end of the test year shows a reduction of -0.22%.[8] Furthermore, Staff utilized the same customer count projections as the Company, indicating no material difference in assumptions.

Q. Are there any other concerns around Staff's sales increase suggestion?

A. Yes. Staff's proposed increase in commercial sales appears to be based solely on the output of their regression modeling, without incorporating additional context or expert judgment. This narrow approach overlooks the importance of integrating recent trends and forecaster experience, which are essential for producing accurate and responsive load projections.

Q. Why is it a concern that Staff's forecast focuses solely on its regression model results?

A. It's a concern because in the process of electric load projections, it is imperative that forecasters also utilize the human factor. In other words, the forecaster's experience, viewed through the lens of their expertise, can be very helpful in spotting certain trends, especially in the more recent history. Our models (both the Company and Staff use the

[7] Source data is the S&P Global for key economic indicators as used in both Consumers Energy and Staff regression models.
[8] Source: Part III att 015 and 016. 5/2024 – 4/2025 avg.: 230,281 custs. 5/2026 – 4/2027 avg.: 229,272 custs. CAGR: (229,272/230,281) ^(1/2)-1 = -0.22%.

same historical window) utilize historical data going back over 10 years (January 2014), so more recent trends and developments can be spotted by careful scrutiny in light of the forecaster's professional experience. As the authors of a recent study observed, "Comparative studies of quantitative methods and human judgement show that (1) neither method is universally superior, and (2) the better method varies…suggesting that (3) the two approaches can complement each other to yield more accurate and resilient models."[9] This hybrid approach is very common in the forecasting world as electric load forecasting (as well as customer counts and peak demands) demands both precision and adaptability. Electric load forecasting requires both analytical precision (using regression models) and adaptive insight (based on the forecaster's experience). As explained in my direct testimony, pages 4 and 5, multiple explanatory variables (such as economic indicators, temperature, etc.) are introduced into the regression models, which provides models that offer consistency and scalability, making them indispensable for baseline forecasts. Drawing on over 13 years of utility-specific forecasting experience, I've found that integrating human judgment with model outputs allows for timely adjustments that reflect current conditions more accurately. This hybrid approach, merging statistical models with expertise, results in forecasts that are not only more reliable but also more responsive to change.

Q. In utilizing this hybrid approach, what kind of adjustments did you make to the forecast?

A. Consumers Energy's commercial electric load forecast includes manual adjustments that improve accuracy by aligning recent growth trends with model outputs. These adjustments

[9] Zellner, M., Abbas, A. E., Budescu, D. V., & Galstyan, A. (2021). *A survey of human judgement and quantitative forecasting methods*. Royal Society Open Science, 8(201187). Abstract. https://doi.org/10.1098/rsos.201187.

reflect the latest data on EV adoption, economic activity, and customer growth in the Company's service territory. The final forecast, shown earlier in Figure 2, incorporates both regression modeling and expert judgment to ensure projections match current conditions.

Q. Did Staff's forecast process also use this hybrid approach?

A. No. Staff's forecast relies almost entirely on its regression model output. However, instead of developing its own manual adjustment to reflect recent trends, Staff adopted the Company's absolute adjustment value. While the Company used this adjustment in conjunction with its regression model to align with observed growth rates over the past 12-24 months, Staff applied the same fixed value directly to its own model without further refinement. This approach results in a growth rate that lacks proper justification. As shown in Figure 2, the projected growth appears overstated, especially when considering the downward pressure from EWR savings of -1.8%, annually. And, as mentioned earlier, Consumers Energy's service territory currently is not experiencing the kind of growth factors, in the commercial sector, that can offset the negative growth pressures of EWR and turn it into an annual growth rate of +1.0% by the end of the test year. There is simply no evidence to support this.

Q. Staff has introduced MetrixND regression modeling software for the first time this rate case to aid in assessing test year projections. Have you evaluated their regression model as it relates to the commercial deliveries projections?

A. Yes. With a few exceptions, Staff's regression models closely resemble those developed by Consumers Energy. However, Staff opted to use a different economic variable, non-manufacturing employment, in place of the Company's service employment metric to

drive model growth. Additionally, Staff introduced an extra explanatory variable, labeled "constant," in an effort to enhance the model's performance.

Q. Do you see an issue with Staff's commercial regression model?

A. Not entirely. While Staff's model utilizes a different economic driver (non-manufacturing employment), this variation does not materially affect the final delivery forecasts. Regression models are inherently flexible and can accommodate a broad range of valid explanatory variables. However, the inclusion of a "constant" variable raises concerns regarding the model's statistical robustness and explanatory relevance.

Q. Why is the "constant" variable deficient?

A. As outlined in my direct testimony,[10] the relevance of independent variables, like Staff's constant variable, in regression modeling is typically assessed using statistical indicators such as the t-statistic ("t-stat") and p-value. A t-stat greater than 2 and a p-value below 5% generally indicate that a variable contributes meaningfully to explaining the dependent variable. Variables that fall outside these thresholds should be excluded due to their limited explanatory power.

Staff's newly introduced "constant" variable does not meet these criteria, with a t-stat of 1.43 and a p-value of 15.54%,[11] suggesting it is statistically weak and unlikely to enhance the model's predictive accuracy.

[10] Company witness Breuring, direct testimony, pages 7 (lines 10-23) and 8 (lines 1-4).
[11] Staff witness Ausum, Exhibit S-15.9, "Staff Model Coefficients."

Q. Does the introduction of an independent variable that does not meet standard statistical criteria (e.g. t-stat > 2, p-value < 5%) hurt the model, and should such a variable be removed?

A. Not necessarily. Including a statistically weak variable does not inherently harm the model's performance; however, it also does not contribute meaningful explanatory power. Such a variable may simply add noise rather than insight. While it may not degrade the model's predictive accuracy, its inclusion offers limited value and should be carefully considered, especially when model parsimony and interpretability are priorities.

Q. Do you believe the Company's use of two separate commercial regression models, a 'use-per-customer' model and a 'total delivery' model, results in a less accurate forecast, as suggested by Staff witness Ausum in his direct testimony[12]?

A. I disagree with Staff witness Ausum's characterization of the Company's use of two separate commercial regression models, a "use-per-customer" model and a "total delivery" model, as delivering a less accurate forecast. This dual-model approach does not inherently reduce accuracy; rather, it introduces a valuable level of flexibility, as explained during discovery[13] and allows for cross-validation between different forecasting perspectives. While each model may have its own strengths and limitations, using both helps mitigate the risks associated with relying on a single methodology.

Although one model may appear statistically superior, particularly given that the models use different independent variables and therefore cannot produce identical results, the two-model framework, which is also employed in the Company's residential modeling,

[12] Staff witness Ausum, direct testimony, page 9 (lines 8-18).
[13] Discovery Response No. U21870-ST-CE-0086.

enhances the robustness of the projections. This methodology enables forecasters to balance the strengths and weaknesses of each model.

Since each model yields slightly different results, applying different weightings, in this case 60/40 (60% 'total delivery' and 40% 'use-per-customer'), can offer a more balanced analytical perspective. While it can be argued, as Staff witness Ausum did, that one model may be superior to another, it is important to recognize that no model is perfect. Forecasting methods are inherently subjective and often tailored to the individual forecaster's judgment and experience. Ultimately, accuracy should be evaluated based on the statistical performance of each model and the reasonableness of the final forecast, not solely on the number of models employed.

Q. Staff also suggests an increase in the sales projection of commercial choice of 16,308 MWh. Do you agree with this suggested increase?

A. No. Consumers Energy does not support any increase in its test year sales projections, whether for bundled or choice service, for the reasons outlined throughout this rebuttal testimony.

Q. Does Mr. Ausum suggest any other changes to the test year projections in this case?

A. No.

SUMMARY

Q. Would you please summarize why you disagree with Staff witness Ausum's proposed increase in commercial electric bundled and choice test year deliveries?

A. Consumers Energy disagrees with Staff witness Ausum's recommendation to increase the test year bundled and choice commercial deliveries by 204,656 MWh and 16,308 MWh,

respectively, for a total of 220,963 MWh. The following points summarize Consumers Energy's rebuttal testimony:

- **Historical Trends**: Commercial electric consumption has stabilized post-pandemic, with minimal growth from 2022 to 2024. The proposed increase contradicts this trend.
- **Forecasting Methodology**: Consumers Energy uses a hybrid approach combining regression modeling with expert judgment. This method accounts for recent trends and ensures more accurate projections.
- **Staff's Approach**: Staff relies solely on regression model outputs and applies a fixed adjustment without refinement, resulting in a projected growth rate that lacks empirical support.
- **Economic and Customer Growth Indicators**: Economic indicators and customer count growth are modest (CAGRs of 0.1%–0.17%), insufficient to justify the proposed increase.
- **EV Adoption**: Growth in EVs is already factored into the Company's forecast. Additional EVs required to support Staff's adjustment would imply a 24% underestimation, which is highly unlikely.
- **Regression Model Concerns**: Staff's use of a statistically weak "constant" variable (t-statistic of 1.43, p-value of 15.54%) raises concerns about model robustness and explanatory power.
- **Dual-Model Approach**: Consumers Energy's use of both "use-per-customer" and "total delivery" models enhances forecast reliability through cross-validation, contrary to Staff's critique.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Thank you, Your Honor.

Next we have the direct testimony of Jessica R. Byrom, which consists of a cover page and 48 pages of questions and answers. Ms. Byrom also had rebuttal testimony consisting of a cover page and 29 pages of questions and answers. And as far as Ms. Byrom's exhibits other than the ones that have other witnesses sponsored, she had Exhibit A-53 corrected and I believe that's all for Ms. Byrom.

THE COURT: All right. Are there any objections to the admission of this testimony or this Exhibit?

Hearing none. The direct and rebuttal testimony of Jessica Byrom is bound into the record and Exhibit A-53 corrected is admitted.

(At 2:44 p.m., Exhibit A-53 admitted)

MR. GENSCH: Thank you, Your Honor.

Next is company witness Thomas P. Clark, sponsored direct testimony consisting of a cover page and 11 pages of questions and answers. Mr. Clark also sponsored Exhibits A-54, confidential Exhibit A-55, confidential Exhibit A-56, confidential exhibit A-57, confidential Exhibit A-58, confidential Exhibit A-59, A-60, confidential Exhibit A-61, confidential Exhibit A-62, confidential Exhibit A-63, confidential Exhibit A-64, and confidential Exhibit A-65.

THE COURT: All right. Are there any objections

to the admission of this testimony of these exhibits?

Hearing none. The direct testimony of Thomas Clark is bound into the record. Exhibits A-54 and A-60 are admitted to the public record and exhibits A-55 through A-59 and Exhibits A-61 through A-65 are admitted to the confidential record.

(At 2:46 p.m., Exhibits A-54 and A-60 admitted to public record and Exhibits A-55 through A-59 and Exhibits A-61 through A-65 admitted to confidential record)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U- 21870

DIRECT TESTIMONY

OF

THOMAS P. CLARK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Thomas P. Clark, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. In what capacity are you employed?

A. I am the Executive Director of the Clean Energy Project Development ("CEPD") Department.

Q. Please describe your educational background.

A. I received the degree of Bachelor of Science in Engineering from Western Michigan University in 2004. Since 2010, I have been a Registered Professional Engineer in the state of Michigan. In December 2016, I received the degree of Master of Business Administration from the Ross School of Business at the University of Michigan Ann Arbor.

Q. Please describe your business experience.

A. In August 2004, I joined Consumers Energy as an Electric System Owner. In 2005, I accepted a position as an Engineer in Transactions and Resource Planning responsible for administration of the Resource Conservation Plan and the Qualified Facility Reduced Dispatch Agreements. In this role, I assisted with proposal evaluation and the administration of power purchase contracts. In early 2009, I took on responsibilities associated with the Company's Renewable Energy Plan ("RE Plan"), including the calculation of the Transfer Price associated with renewable energy and capacity and Renewable Energy Credit tracking and forecasting. In June 2013, I was assigned to the Smart Energy Department where I was responsible for the development and

implementation of demand response programs associated with the Company's deployment of Advanced Metering Infrastructure. In March 2015, I accepted the role of Manager of the Company's Resource Planning Department where I was responsible for all the Company's short-, mid-, and long-term electric generation resource planning, including the development of the Company's Integrated Resource Plans ("IRP"). In July 2017, I added Real-Time and Day-Ahead Midcontinent Independent System Operator, Inc. ("MISO") Market Operations to my Resource Planning responsibilities. In March 2021, I was promoted to Executive Director of Electric Supply where I had responsibility for purchasing and transport functions for fuel for electric generation, interaction in the MISO markets, Power Supply Cost Recovery ("PSCR") activities, wholesale settlement and transaction functions, and contract strategy functions including distribution agreements, solicitations for energy and capacity, renewable energy compliance, and distributed generation programs. In December 2021, I was assigned my current role of Executive Director of the CEPD where I am responsible for the development and acquisition of all Company-owned renewable energy resources, including solar, wind, and storage projects.

Q. Have you previously presented testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in the following cases:

- Case No. U-15675-R, the Company's 2009 PSCR Reconciliation;
- Case No. U-16300, the Company's 2009 Renewable Cost Reconciliation;
- Case No. U-16543, the Company's RE Plan Amendment;
- Case No. U-16045-R, the Company's 2010 PSCR Reconciliation;
- Case No. U-16301, the Company's 2010 Renewable Cost Reconciliation;
- Case No. U-16581, the Company's Biennial RE Plan Review;

- Case No. U-16432-R, the Company's 2011 PSCR Reconciliation;
- Case No. U-16655, the Company's 2011 Renewable Cost Reconciliation;
- Case No. U-17301, the Company's 2013 Biennial RE Plan Review;
- Case No. U-17321, the Company's 2012 Renewable Cost Reconciliation;
- Case No. U-18250, the Company's application for a financing order approving the securitization of qualified costs and related approval;
- Case No. U-18322, the Company's 2017 Electric Rate Case ("ERC");
- Case No. U-20165, the Company's 2018 IRP;
- Case No. U-20963, the Company's 2021 ERC;
- Case No. U-21090, the Company's 2021 IRP;
- Case No. U-21224, the Company's 2022 ERC;
- Case No. U-21389, the Company's 2023 ERC;
- Case No. U-21585, the Company's 2024 ERC; and
- Case No. U-21816, the Company's RE Plan Amendment.

Q. What is the purpose of your direct testimony in this proceeding?

A. My testimony provides background, informational updates and support for capital expenditures associated with new Battery Energy Storage System ("BESS") projects. Specifically, my testimony discusses two BESS projects:

- Iosco BESS Project – a 30 MW/120 MWh battery located in Oscoda Township, Iosco County, that was initially approved in Case No. U-21585, the Company's 2024 ERC. The Iosco BESS Project is being developed and constructed to support the 75 MW BESS Deployment Program approved as part of the settlement of the 2021 IRP; and
- Weadock BESS Project – 45 MW/180 MWh battery located in Hampton, Township, Bay County, that was initially approved in Case No. U-21585, the Company's 2024 ERC. The Weadock BESS Project is being developed and constructed to support the 75 MW BESS Deployment Program approved as part of the settlement of the 2021 IRP.

Q. Please detail how your direct testimony is related to the direct testimony of other Company witnesses.

A. The Iosco BESS and Weadock BESS projects associated capital spending supported in my testimony are a subset of the overall generation capital expenditure plan explained and sponsored by Company witness Richard T. Blumenstock and presented in Exhibit A-12 (RTB-3), Schedule B-5.2.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-54 (TPC-1)	Weadock BESS Project – Milestone Schedule;
Confidential Exhibit A-55 (TPC-2)	Weadock BESS Project – Substation Transformer Agreement by and between Virginia Transformer Company and Consumers Energy Company, dated March 1, 2024;
Confidential Exhibit A-56 (TPC-3)	Weadock BESS Project – Purchase Order by and between Virginia Transformer Company and Consumers Energy Company, dated March 7, 2024;
Confidential Exhibit A-57 (TPC-4)	Weadock BESS Project – EPC Contract between Rauhorn Electric, Inc. and Consumers Energy Company, dated August 2, 2024;
Confidential Exhibit A-58 (TPC-5)	Weadock BESS Project – Major Procurement Contract between Our Next Energy, Inc. and Consumers Energy, dated August 2, 2024;
Confidential Exhibit A-59 (TPC-6)	Weadock BESS Project – Contract Change Order #1 to the Major Procurement Contract by and between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated December 18, 2024;
Exhibit A-60 (TPC-7)	Iosco BESS Project – Milestone Schedule;

Confidential Exhibit A-61 (TPC-8)	Iosco BESS Project – Substation Transformer Agreement by and between Virginia Transformer Company and Consumers Energy Company, dated March 1, 2024;
Confidential Exhibit A-62 (TPC-9)	Iosco BESS Project – Purchase Order by and between Virginia Transformer Company and Consumers Energy Company, dated March 7, 2024;
Confidential Exhibit A-63 (TPC-10)	Iosco BESS Project – EPC Contract between Rauhorn Electric, Inc. and Consumers Energy Company, dated August 2, 2024;
Confidential Exhibit A-64 (TPC-11)	Iosco BESS Project – Major Procurement Contract between Our Next Energy, Inc. and Consumers Energy Company dated August 2, 2024; and
Confidential Exhibit A-65 (TPC-12)	Iosco BESS Project – Contract Change Order #1 to the Major Procurement Contract between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated December 18, 2024.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes. The Major Procurement Contracts for the Iosco BESS and Weadock BESS projects were negotiated by my organization and executed in the normal course of business. These contracts were also signed by an officer of Consumers Energy.

IRP BESS 75 MW DEPLOYMENT PROGRAM

Q. Please provide an overview of the Company's IRP BESS 75 MW Deployment Program.

A. In Case No. U-21090, the Company's 2021 IRP, and corresponding Settlement Agreement, dated June 23, 2022, the Company agreed to add 75 MW of battery capacity between 2024 and 2027.

Q. What requirements were requested for inclusion in the Company's battery deployment program?

A. As presented in the rebuttal testimony of Company witness Blumenstock in Case No. U-21090 the Company proposed the following requirements for its battery deployment program:

- The Company will use the battery resources included in the program in isolation or in combination with the other resource sets identified in the PCA (i.e., solar, Energy Waste Reduction, Demand Response);
- The battery resources, and any battery plus resource combinations, are to be owned by Consumers Energy to facilitate an expedited pace of installation and learnings;
- The Company will conduct an all-battery request for proposal ("RFP") to develop the most economic battery projects. The RFP will consider Company bid resources as well as Build Transfer Agreements and other similar arrangements;
- The battery resources will not be used to set the Public Utility Regulatory Policies Act of 1978 full avoided cost rates and therefore, will not be subject to the same competitive procurement guidelines as the IRP solicitations;
- The Company will have flexibility to procure solar plus storage options in the above discussed solicitations;
- The Company will have the flexibility to adjust amounts of annual battery deployment based upon economics of the bid proposals resulting from the RFP; and
- To the extent possible, siting of projects will be implemented in localized areas identified as providing potential benefits to the distribution systems' reliability, resiliency, and performance with a focus on vulnerable communities.

Q. What has been the Company's progress with its battery deployment program?

A. The Company conducted customer outreach, identified two specific project sites, issued two battery deployment solicitations, evaluated the proposals, executed all necessary

contracts and procurements, and began the design process for both projects. Both projects were presented in the Company's 2024 Electric Rate Case.

Q. Please describe the Weadock BESS Project?

A. The Weadock BESS Project is a 45 MW/180 MWh lithium-ion battery energy storage system interconnected at the Weadock Substation on the Company's 46 kV high voltage distribution system located in Essexville, Bay County. The purpose of this project is to provide localized grid support and provide data regarding how battery storage could benefit the reliability, resiliency, and performance of the high voltage distribution system as well as provide energy arbitrage and firm dispatchable capacity in the MISO market. This project will be constructed on Company-owned property within the Karn/Weadock Generating complex. The project has been executed utilizing Major Procurement Agreements for Engineering, Procurement, and Construction ("EPC"); Substation Transformer Unit; and Battery Supply Agreements ("BSAs").

Q. Does this project require Board of Directors approval?

A. No. The project does not require Board of Director approval.

Q. What is the project schedule?

A. The Weadock BESS Project is scheduled to begin commercial operation on December 21, 2026. See Exhibit A-54 (TPC-1) for further detail regarding the project schedule.

Q. Which Major Procurement Agreements has the Company executed to date?

A. The Company has executed the Substation Transformer Unit agreement, EPC, and BSA. Confidential Exhibit A-55 (TPC-2) and Confidential Exhibit A-56 (TPC-3) references the Substation Transformer Agreement and associated Purchase Order with Virginia Transformer, dated March 1, 2024, and March 7, 2024, respectively. Confidential Exhibit

A-57 (TPC-4) is the EPC Agreement with Rauhorn Electric dated August 2, 2024, and Confidential Exhibit A-58 (TPC-5) is the Major Procurement contract with Our Next Energy, Inc. ("Our Next Energy") dated August 2, 2024.

Q. Have there been any significant changes to these contracts?

A. Yes. Energy Vault, Inc. ("Energy Vault") will assume the BSA previously executed with Our Next Energy. Energy Vault has agreed to all terms and conditions of the BSA, except as explicitly stated in Contract Change Order #1 (Confidential Exhibit A-59 (TPC-6) dated December 18, 2024.)

Q. What necessitated the transition to Energy Vault?

A. Our Next Energy was unable to provide sufficient project financial risk mitigation, as required under the terms of the BSA. Consequently, Our Next Energy contacted Energy Vault, a company with over 300 MW of projects currently under construction and more than 500 MW of deployed BESS and Hybrid Energy Storage Systems ("HESS"), with the intention to have Energy Vault assume the BSA. The Company evaluated Energy Vault's financial risk and determined that they were well positioned to address the issues present with Our Next Energy.

Q. What is the projected cost of the Weadock BESS Project?

A. Table 1 below represents the Weadock BESS Project's actual and projected capital spending based on the project schedule.

Table 1: Iosco and Weadock BESS Capital Expenditure

Line No.	Description		Bridge Year	Test Year	Total Capital
		12/31/2024	16 Months Ending 4/30/2026	12 Months Ending 4/30/2027	
	(a)	(b)	(c)	(d)	(e)
1	Iosco BESS Project	$ 8.39	$ 30.05	$ 11.46	$ 49.90
2	Weadock BESS Project	$ 11.95	$ 40.56	$ 14.93	$ 67.45
3					
3	Total	$ 20.34	$ 70.61	$ 26.39	$ 117.34

The Company projects that it will spend $40,560,000 in the Bridge Period and $14,930,000 in the Test Year, bringing the total projected capital expenditures to $67,450,000. These values are estimated based on the executed Substation Transformer Agreement, BSA, and EPC Contract, along with the Company-approved overheads and loadings.

Q. Why have the project costs increased?

A. The revised and updated costs provide a more precise reflection of project costs and loadings based upon the current commercial operation dates.

Q. Has the Company included any contingency in the projected capital expenditure for the project?

A. No. Company witness Blumenstock will address the Company's position regarding contingency for Company-owned projects in his testimony.

Q. Please describe the Iosco BESS Project?

A. The Iosco BESS Project is a 30 MW/120 MWh lithium-ion battery energy storage system interconnected at the Iosco Substation on the Company's 46 kV high voltage distribution system located near the City of Oscoda, Iosco County. The purpose of this project is to provide localized grid support and provide data regarding how battery storage could benefit the reliability, resiliency, and performance of the high voltage distribution system as well as provide energy arbitrage and firm dispatchable capacity in the MISO market. This

project will be constructed on existing Company-owned property near the existing Iosco Substation. The project has been executed utilizing Major Procurement Agreements for EPC; Substation Transformer Unit; and BSA.

Q. Does this project require the Board of Directors approval?

A. No. The project does not require the Board of Directors Approval.

Q. What is the project schedule?

A. The Iosco BESS Project is scheduled to begin commercial operation on December 21, 2026. See Exhibit A-60 (TPC-7) for further detail in regard to the project schedule.

Q. Which Major Procurement Agreements has the Company executed to date?

A. The Company has executed the Substation Transformer Unit agreement, EPC, and BSA. Confidential Exhibit A-61 (TPC-8) and Confidential Exhibit A-62 (TPC-9) references the Substation Transformer Agreement and associated Purchase Order with Virginia Transformer, dated March 1, 2024 and March 7, 2024, respectively. Confidential Exhibit A-63 (TPC-10) is the EPC Agreement with Rauhorn Electric dated August 2, 2024 and Confidential Exhibit A-64 (TPC-11) is the Major Procurement Contract with Our Next Energy dated August 2, 2024.

Q. Have there been any significant changes to these contracts?

A. Yes. Energy Vault, Inc. will assume the BSA previously executed with Our Next Energy. Energy Vault has agreed to all terms and conditions of the BSA, except as explicitly stated in Contract Change Order #1 Confidential Exhibit A-65 (TPC-12) dated December 18, 2024.

Q. What necessitated the transition to Energy Vault?

A. Our Next Energy was unable to provide sufficient project financial risk mitigation, as required under the terms of the BSA. Consequently, Our Next Energy contacted Energy Vault, a company with over 300 MW of projects currently under construction and more than 500 MW of deployed BESS and HESS, with the intention to have Energy Vault assume the BSA. The Company evaluated Energy Vault's financial risk and determined that they were well positioned to address the issues present with Our Next Energy.

Q. What is the projected cost of the Iosco BESS Project?

A. Table 1 above provides the Iosco BESS Project's actual and projected capital spending based on the project schedule. The Company projects that it will spend $30,050,000 in the Bridge Period, $11,460,000 in the Test Year bringing the total projected capital expenditures to $49,900,000. These values are estimated based on the executed Substation Transformer Agreement, BSA, and EPC Contract, along with the Company-approved overheads and loadings.

Q. Why have the project costs increased?

A. The revised and updated costs provide a more precise reflection of project costs and loadings based upon the current commercial operation dates.

Q. Has the Company included any contingency in the projected capital expenditure for the project?

A. No. Company witness Blumenstock will address the Company's position regarding contingency for Company-owned projects in his testimony.

Q. Does this conclude your direct testimony?

A. Yes.

MR. GENSCH: Thank you, Your Honor. Next is company witness, Amy M Conrad whose direct testimony consisted of a cover page and 40 pages of questions and answers. Ms. Conrad also had rebuttal testimony consisting of a cover page and 10 pages of questions and answers and Ms. Conrad's sponsored Exhibits A-71, A-72, A-73, and A-74.

THE COURT: Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct testimony of Amy Conrad is going into the record and Exhibits A-71 through A-74 are admitted.

(At 2:47 p.m., Exhibits A-71 through A-74 admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. In what capacity are you employed?

A. I am employed as the Director of Compensation Operations for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. I graduated from Central Michigan University in 1999 with a Bachelor of Science Degree in Business Administration with a major in Accounting. In addition, I am designated as a Certified Compensation Professional and Certified Executive Compensation Professional by WorldatWork and a Certified Public Accountant by the Michigan Association of Certified Public Accountants. WorldatWork is an international professional organization focused on human resources issues, including compensation, benefits, work life, and integrated total rewards to attract, motivate, and retain a talented workforce.

Q. What have your job responsibilities entailed with Consumers Energy?

A. In February 2002, I joined Consumers Energy as a Financial Reporting and Technical Accounting Analyst. My duties included accounting and reporting of equity-based compensation, technical accounting standard research, and preparation of quarterly and annual Securities and Exchange Commission ("SEC") filings. After eight years of progressing responsibilities in this role, I transferred to the position of Principal Human Resources Consultant. In 2013, I was promoted to the position of Director of Compensation. In this role I had the responsibility for administering Consumers Energy's compensation function and partnering with Labor Relations on union compensation

matters. This included developing compensation programs designed to attract and retain a qualified workforce for the Company. My duties included gathering of comparable wage and salary data in order to determine how Consumers Energy's pay level compares to the labor market and developing compensation programs that are competitive and deliver pay to employees that is fair and equitable and that motivates employees to perform at their full potential.

My responsibilities also consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers.

In May 2018, I took on the role of Director of Executive and Incentive Compensation. My responsibilities consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers. My responsibilities also included administering the incentive plans for CMS Energy, including Consumers Energy.

In August 2023, I took on the role of Manager of Compensation Operations. My Manager of Compensation Operations responsibilities consisted of the implementation of new and revised non-officer compensation programs, policies, and procedures for non-officers to align with the Company's goals and competitive practices. This position is also responsible for ensuring that compensation programs are consistently administered in compliance with internal policies and government regulations. The Manager of Compensation Operations role focuses primarily on the coordination and implementation

of the non-officer merit, incentive, stock administration, survey participation, and ensuring accuracy of data for non-officer programs.

In January 2024, I took on the role of Director of Compensation. My Director of Compensation responsibilities consist of the implementation of new and revised officer and non-officer compensation programs, policies, and procedures for officers and non-officers to align with the Company's goals and competitive practices. This position is also responsible for ensuring that compensation programs are consistently administered in compliance with internal policies and government regulations. The Director of Compensation Operations role focuses primarily on the coordination and implementation of the officer and non-officer merit, incentive, stock administration, survey participation, and ensuring accuracy of data for officer and non-officer programs. Lastly, the Director of Compensation consists of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers. In February 2025, I returned to the Manager of Compensation Operations role which I previously held from August 2023 through December 2023.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have testified in Case Nos. U-17087, U-17197, U-17643, U-17735, U-17882, U-17990, U-18124, U-18322, U-18424, U-20134, U-20322, U-20650, U-20697, U-21148, U-21224, U-21308, U-21389, U-21490, and U-21806.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for costs of its annual Employee Incentive Compensation Plan ("EICP") at target levels. The EICP is a form of short-term incentive. Short-term incentive pay is designed to focus and reward performance over periods of approximately one year or less.

First, I will discuss Consumers Energy's overall compensation philosophy. In this section of my direct testimony, I will discuss the importance of paying employees a competitive level of compensation and the reasonableness of the overall compensation levels that the Company is requesting in this case. In addition, I will discuss (i) the fact that EICP compensation is part of an employee's overall market-based compensation and not in addition to it, and (ii) why Consumers Energy has included EICP at target levels as part of overall market-based compensation.

Second, I will discuss the EICP incentives and provide support for the Company's request for rate recovery in this case related to Consumers Energy's non-officer and officer operational goal portion of EICP. In my direct testimony, I will discuss the design of the EICP.

Third, I will discuss customer-related benefits that result from use of the incentive plans and how customers are best served when Consumers Energy can attract, retain, and motivate a talented workforce with compensation packages that are competitive and fair. Elimination of the EICP would result in Consumers Energy's employee compensation being below market and would hinder the Company's ability to attract and retain a qualified workforce that best serves customers.

Q. Please summarize your conclusions.

A. My conclusions include the following: (i) use of incentive compensation by utility companies is an accepted, common, and reasonable practice; (ii) Consumers Energy's decision to make a portion of compensation at-risk and subject to incentives is reasonable; (iii) the amount of overall compensation included by Consumers Energy in this case is reasonable and is reasonably necessary to attracting and retaining a talented workforce; (iv) incentive compensation is part of the reasonable level of market-based compensation and not in addition to it; (v) recovering costs of Consumers Energy's EICP employee incentive plans will not result in excess rates; (vi) Consumers Energy's EICP performance goals and thresholds provide customer-related benefits; and (vii) the EICP goals provide customer-related benefits at no incremental cost to customers above those included in market-based compensation.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. OVERVIEW

II. EMPLOYEE COMPENSATION PHILOSOPHY

III. INCENTIVE COMPENSATION PLANS

A. Description of Incentive Plans

B. Assessment of Customer Benefits of the Incentive Compensation Plans

IV. CONCLUSION

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-71 (AMC-1) EICP Performance Measures;

Exhibit A-72 (AMC-2)	Target Pay Level Market Analysis;
Exhibit A-73 (AMC-3)	Summary of Actual and Projected – Annual Incentive O&M Expenses; and
Exhibit A-74 (AMC-4)	Summary of Officer Compensation - Proxy Data.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

I. OVERVIEW

Q. What is the Company's compensation philosophy for non-officer employees?

A. Consumers Energy's compensation philosophy for its non-officer, non-union employees is to provide market-based compensation tied to performance. A competitive compensation policy benefits customers by attracting and retaining employees with the necessary skills and experience to deliver world-class customer service and minimize the risks and costs of employee turnover. Incentive pay is a component of providing market-based compensation.

Q. What is the Company's compensation philosophy for officer employees?

A. Consumers Energy's compensation philosophy for its officers is centered around four principles:

1. Align with increasing shareholder and customer value;
2. Enable the Company to compete for and secure top executive talent;
3. Reward measurable results; and
4. Be fair and competitive.

Incentive pay is a reasonable component of delivering this philosophy.

Q. How does Consumers Energy structure non-officer compensation for its salaried employees?

A. Consumers Energy first determines what a competitive level of pay is for salaried non-officer employees. It does so by using various market surveys. The practice of using multiple surveys is common practice. It allows for a broader participant pool and confirmation that the survey data is representative of market competitive wages and trends. Consumers Energy then structures the compensation by allocating this market-based wage between base salary and incentive compensation. The incentive compensation is part of the overall total market-based competitive level and it is not in addition to it.

Q. How does Consumers Energy structure officer compensation?

A. Officer compensation levels are determined by the Compensation Committees of the Boards of Directors of Consumers Energy and CMS Energy. The Company creates a compensation package for officers that delivers base salary, annual incentive compensation, and long-term incentive compensation targeted at the median or 50th percentile of the competitive market. In determining individual officer compensation levels, the Compensation Committees are advised by an independent third-party consultant and take into consideration market research, experience levels, and individual contributions.

Q. In this proceeding, is the Company requesting rate recovery of all Operating and Maintenance ("O&M") electric expenses related to short-term incentive compensation plans?

A. No. The Company utilizes both financial and non-financial (operational) goals in its short-term incentive compensation plan. While the Company believes that both financial

and non-financial (operating) short-term incentive compensation expenses are reasonable, the Company in this case is excluding the costs of short-term incentive compensation linked to financial goals ($6.9 million). Included in that $6.9 million amount is the removal of the affordability (O&M savings) operational measure. The Company determined that the affordability measure, although included among the Company's operational goals for purposes of the EICP, is financial in nature; therefore, the Company removed the dollars attributable to that measure from the rate request in this case along with the dollars attributable to the other financial measures.

Q. Is Consumers Energy requesting recovery of all officer incentive pay linked to non-financial (operational) goals in this rate case proceeding?

A. Yes. The Company is seeking recovery for the incentive costs associated with the operational goals portion for all officers in this case. This is a result of 30% of officer pay directly linked to operational measures.

Q. Is Consumers Energy requesting recovery of long-term incentive pay in this rate case proceeding?

A. No. The Company is not seeking recovery for the costs of long-term incentive compensation (sometimes referred to as restricted stock plans) in its rate recovery request in this case.

Q. Why is the Company requesting rate recovery of short-term incentive compensation operational goal expenses?

A. Consumers Energy uses market data to determine an overall competitive level of compensation. Competitive compensation includes base salary and short-term incentive compensation for officers and non-officers. Consumers Energy's overall compensation

levels are reasonable compared to the market. Compensation levels without these incentive payments would be below market competitive levels. Paying non-competitive levels of compensation would result in a less qualified workforce that would not best serve customers. A March 2025 ManpowerGroup report stated nearly three-quarters of employers, 71%, still struggle to find skilled talent, according to ManpowerGroup's latest Talent Shortage survey. This marks a jump from a decade ago, when only 40% of employers reported such challenges. In order to hire and retain qualified personnel, it is necessary to either pay a competitive incentive or increase base salaries to make up for the missing incentive compensation component. Use of annual incentive mechanisms is a recognized management technique for companies, including utility companies. As I discuss later in my direct testimony, incentive pay is the number one compensation design element used to influence short- to mid-term performance results. Incentive mechanisms help communicate priorities, engage the employees in operating and financial success, reward valued skills and behaviors, and create business understanding for employees. Consumers Energy's incentive programs are structured in a way that is designed to help keep non-officers and officers focused on operational performance areas such as continuous improvement, safety, cost, reliability, and delivery. The incentive compensation program encourages employees to deliver outcomes which result in meeting customers' expectations. The EICP incentive compensation costs are reasonable costs of doing business and, therefore, should be recovered in rates.

Q. Who is eligible for the EICP incentives?

A. All non-union employees are eligible for EICP incentives, with the exception of employees who are rated as "under-performing" or "needs improvement" on their annual performance

appraisals. These under-performing employees are ineligible to receive an EICP incentive. Both non-officers and officers participate in an annual EICP incentive.

Q. How are the EICP incentives structured?

A. The EICP incentives are structured by non-officer and officer EICP. The 2024 non-officer EICP equally weights the operational measures with the financial measures:

- Half (50.0%) of employees' incentive will be based on the achievement of operational performance measures. (For 2024 and 2025, there are six operational measures.); and
- Half (50.0%) of employees' incentive will be based on the achievement of one financial measure, Earnings Per Share ("EPS"). Consumers Energy is a vital part of the Michigan economy, and it is important that the utility remains financially strong so that it can provide the utility service that customers expect and deserve; however, Consumers Energy is not seeking recovery of the financial portion of the EICP.

The goals are the same for the officer EICP, but the weightings are different. Officers are 30% based on the achievement of operational measures and 70% based on the achievement of financial measures.

II. EMPLOYEE COMPENSATION PHILOSOPHY

Q. What is Consumer Energy's philosophy about the overall level of compensation?

A. The Company's management believes Consumers Energy should pay a fair and reasonable salary, comparable to the market that is equitable to employees, consistent with Company values and strategies, and that supports the highest level of customer service at a reasonable cost.

Q. What are the components of Consumers Energy's compensation for non-officer employees?

A. There are two parts of overall compensation for non-officer employees of Consumers Energy. The first part is base pay or salary. The second part for salaried employees is annual incentive compensation.

Q. What are the components of Consumers Energy's compensation for officers?

A. There are three parts of overall compensation for officers of Consumers Energy. The first two parts are cash compensation through base pay and annual incentive compensation. The third part is equity-based long-term incentive. As I mentioned earlier in my direct testimony, the Company is not seeking recovery for the costs of long-term incentive compensation in its rate recovery request in this case.

Q. Why does the Company make a portion of compensation subject to incentives?

A. A wide body of research supports the view that incentive pay (a variable pay component) works. One researcher states, "theory and research show that incentive pay can substantially increase individual and organizational performance and can represent a powerful tool for establishing a competitive advantage within an industry." (Dow Scott, *Incentive Pay: Creating a Competitive Advantage* – WorldatWork Press, 2007). There are many more cases of incentive plans as an effective motivational tool. Group incentive plans can contribute to organizational collaboration and achievement of company goals which lead to benefits for customers. A May 15, 2018, Forbes article entitled "The Key to an Effective Incentive Plan" (Bill Fotsch and John Case) continues to support this theory indicating:

> Incentive plans, by definition, are supposed to affect people's behavior on the job, day in and day out. They incent

> people to work harder and smarter, to go the extra mile, to collaborate with their coworkers, to come up with new ideas to improve some aspect of the business.

People don't work for money alone, but they do respond to incentives.

When properly selected and implemented, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal. In addition, incentives increase a company's ability to attract, hire, and retain qualified and motivated individuals. A study by the International Society of Performance Improvement showed that incentive pay programs increase performance by an average of 22.0%. (International Society of Performance Improvement, "Incentives Motivation and Workplace Performance Research and Best Practices," Spring 2002). As stated by the Society of Human Resource Management:

> Research has demonstrated that some human resource programs and initiatives produce a significant impact on performance in organizations (as measured by factors such as quality, productivity, speed, customer satisfaction and unwanted turnover). The two initiatives that consistently showed statistically significant positive results were linking pay to performance and using variable pay. Research has established the potential of variable pay to produce the desired business results. [Robert Greene, "Variable Pay: How to Manage it Effectively, Society of Human Resource Management," April 2003.]

Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers. High-level qualitative

customer benefits are listed later in my testimony. Company witness Ashley E. Meschke's testimony illustrates the quantitative benefits to customers.

Q. Are the overall compensation levels for employees subject to the non-officer EICP reasonable?

A. Yes. Overall compensation levels for employees subject to the non-officer EICP and management's decision of how to allocate the overall compensation between base salary and EICP are reasonable. As stated later in my testimony, it is common practice for companies to have a variable pay (i.e. EICP) component of total competitive compensation levels.

Q. How does Consumers Energy determine what level of overall compensation for non-officers is reasonable?

A. First, Consumers Energy's management targets compensation to the market median. Second, Consumers Energy's management actively reviews compensation levels so that employees are neither overpaid nor underpaid relative to the market. Third, the Company uses a rigorous survey process which uses valid and reliable data from multiple third-party sources to determine median levels of compensation. Fourth, the Company reviews incentive compensation levels from third-party data sources to determine the target level of compensation. The fact that a portion of the compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. To the contrary, removing the incentive from employees' compensation package or failing to meet incentive performance goals, would render their compensation below-market.

Q. Would it be reasonable for Consumers Energy to pay employees below market level on an ongoing basis?

A. No.

Q. Why would it be unreasonable for Consumers Energy to pay below market level?

A. Consumers Energy has a responsibility to customers to employ a competent workforce that is ready, willing, and best able to provide service for its customers. Paying competitive wages and salaries is necessary to fulfill that commitment. It would not be reasonable or fair to the Company, its employees, or customers for the MPSC to set rates at a level that did not include reasonable levels of overall market-based compensation.

The level of service that customers deserve requires a qualified, experienced, and motivated workforce. The Company can attract, retain, and motivate talented employees when its overall compensation is competitive with market levels. A decision to compensate employees below market levels would detract from the Company's ability to assemble the committed and customer-focused workforce that customers deserve. Over time, this would be detrimental to customers, as well as being unreasonable to the Company's diligent, hardworking employees. Compensating employees below market levels will eventually result in their leaving for jobs that are paying at market levels. Over time, the workforce would tend to be less qualified, less experienced, less productive, and less capable of serving customers (as the most capable would, in general, tend to go to employers paying at competitive levels). This, in turn, could lead to less efficiency and could result in a need to hire more employees to produce the same service to customers, thus increasing costs to customers.

Q. How does the Company determine the level of compensation for salaried non-officer employees?

A. For salaried non-officer employees, the Company uses salary survey data from utility and energy companies. Using this survey data, a benchmarking analysis of base pay and incentive pay is made between the Company's jobs and comparable survey jobs. Benchmarking analysis is a comparison of jobs commonly found in the labor marketplace and/or a job that is highly relevant/populated within a company. This comparison indicates where the Company's pay stands relative to the market. The Company's goal is to target base pay levels within plus or minus 5.0% of the market median for non-officers. While pay for individuals inevitably varies from the survey market levels due to differences in experience levels, education, job performance, longevity, position responsibilities, etc., the survey data indicate that the Company's overall non-officer compensation levels, assuming the EICP payment at the target level, are on average within target pay level of plus or minus 5.0% of market median. Exhibit A-72 (AMC-2) provides a summary of average exempt and non-exempt base pay for Company benchmark jobs compared to market using 2024 data for 2025 pay structure purposes.

Paying compensation that approximates the market median is particularly important given that Consumers Energy will continue to experience significant attrition (current employees eligible for retirement is 19% of the workforce) and have a need over the next few years to hire engineers, information technology, and other personnel to staff various projects and serve customers. Competitive pay is necessary to retain the talent needed to deliver on the Company's Integrated Resource Plan ("IRP"). In competing for engineers, as well as other personnel that are skilled, high-performing customer-focused

candidates, it will be important to have a reputation for paying a competitive level of overall compensation. Excluding the incentive target amounts would result in the Company's pay levels being as much as or greater than 10.0% below market level.

Q. How do you know the market data that the Company is using are appropriate and are not inflating salary levels?

A. The Company uses several third-party survey sources to compare to the non-officer salaried workforce. The Company participates in and uses an industry survey performed by Willis Towers Watson, Aon Hewitt ("Aon"), and Mercer LLC ("Mercer"), which are well-respected, independent third-party compensation experts. These surveys are conducted by surveying companies which report data on an anonymous basis. When using the survey data, the Company looks at the base pay and incentive reported for highly populated jobs for which there is a comparable job match. In this way, the Company is matching the relevant market, not trying to lead the market, and thus not inflating its overall compensation above prevailing market levels. By using multiple independent survey sources, the Company can determine if any one source is varying significantly from another.

Q. Can you give an example of the relationship between the Company's base pay levels and the market's pay levels?

A. See Exhibit A-72 (AMC-2) for a summary of average exempt and non-exempt base pay for Company benchmark jobs.

Q Does the Company attempt to keep salaries consistent with the rate of inflation?

A. No. The Company's pay levels are designed to stay consistent with the costs of labor. Labor costs and rate of inflation are not interchangeable. Cost of labor is what a particular

geographic market offers as the "going rate" or compensation for its jobs. Inflation is a measure of the rate of rising prices of goods and services in an economy. Labor rates and inflation rates can change based on different factors or influences and at different rates. Labor rates follow what companies are doing to stay competitive, inflation follows economic trends which can be unrelated to how people are paid. Consumers Energy's compensation is designed to be competitive with what is seen in the labor market including rewarding and motivating talent rather than trying to keep up with inflation. For rate making purpose, the Company follows the direction of the Commission's December 22, 2021 Order in Case No. U-20963[1] and uses the same inflation factor to adjust both labor and non-labor expenses for determining projected labor costs.

Q. Are incentive plans common in the utility industry?

A. Yes, incentive plans are quite common. Annual incentive programs are a critical and highly integral part of competitive compensation packages for many organizations. Research from Willis Towers Watson's 2012 Survey Report indicates that approximately 80.0% of companies offer annual incentive (variable pay) programs. That number is slightly higher at 81.2% for those companies within the utility industry sector. The survey data supports the conclusions that including incentive pay as part of a competitive pay package is a standard industry practice and is required to attract and retain good employees.

Research from Mercer's 2014/2015 U.S. Compensation Planning Survey Report indicates that approximately 83.0% of companies offer annual incentive (variable pay) programs. For companies within the utility industry sector, the survey indicated that

[1] See pp. 244-251 for the discussion regarding inflation rates.

98.0% of executives, 99.0% of management, 94.0% of non-sales professionals, and 86.0% of clerical and technicians were eligible for an annual incentive.

A 2012 Mercer study of more than 1,200 organizations reveals that actual company spending on variable pay for salaried exempt employees, as a percentage of pay, is 12.0% and salaried/hourly non-exempt employees, as a percentage of pay, is 6.0% to 7.0% for energy companies. A 2009 Hewitt Associates study of more than 1,100 organizations further reports that companies were budgeting variable pay for salaried exempt employees at 11.8%, and 5.5% to 6.1% for salaried/hourly non-exempt employees, for 2010. Ken Abosch, leader of Hewitt's North American Broad-Based Compensation Consulting business, added:

> Over the past decade, we've seen companies steadily shift from a fixed pay model to one that emphasizes true performance-based awards, and we expect this trend will continue.

Consumers Energy's practice of making a portion of overall employee compensation subject to incentives is consistent with best practices for compensation.

Q. What has been the trend in variable or incentive pay?

A. A 2016 study by Aon indicated a 72% growth in variable pay spend over the past 20 years. Variable pay grew from 4.1% of base salaries in 1996 to 12.9% of base salaries in 2015. Business incentive plans are the most prevalent with 77% of companies using this type of variable pay award in 2015 up from 55% in 1996. Business incentive plans refer to plans that are based on Company financial and/or operational goals. According to a 2021 study published by WorldatWork and Compensation Advisory Partners, the vast majority of companies (99%) have short-term incentive programs ("Incentive Pay Practices: Publicly Traded Companies," July 2021, WorldatWork and Compensation Advisory Partners).

Moreover, a 2020 study by Willis Towers Watson on Salary Increases shows that 89% of energy companies utilized short-term incentive (EICP) compensation programs.

Q. Why is the use of incentive pay such a widespread practice?

A. Incentive pay is the number one design used to influence short- to mid-term business or performance results. Coupled with clear strategy, solid leadership, and good, safe working conditions, variable pay incentive designs:

- Increase employees' understanding of what is important to the Company;
- Increase employees' identification with the Company's success and the factors by which it is measured;
- Reward valued skills and behaviors; and
- Enhance employee engagement by educating them on how and why their contributions will benefit them, the Company, and our customers.

Dividing overall compensation between base salary and incentive compensation is an approach that is common and effective in business today.

Q. How many employees does the Company have that will be eligible for the non-officer EICP payout?

A. Consumers Energy has approximately 4,500 employees (total utility) who are eligible to receive an incentive if, and when, the requirements for a payout are met. The risk of no payout is the same for all these eligible employees. Either every eligible employee receives a payout, or no one receives any incentive compensation.

Q. How did the Company determine the level of compensation that would be provided as incentive compensation for these eligible employees?

A. For the historical test year, the EICP target level for each pay grade was established by reviewing third-party market data on the mix of base salary and at-risk variable pay (EICP),

historical rate case relief and amounts that will assist in motivating performance that will result in benefits to customers. The EICP compensation is part of the overall market-based competitive level of compensation, not in addition to it. Beginning in 2024, the EICP target levels are based on career stream and job level established by reviewing third-party market data on the mix of base salary and at-risk variable pay.

Q. Explain if the Company reduced base pay when it started to pay incentive awards in order to obtain market-based pay based on the combination of the two components of pay.

A. The Company has always had a broad-based incentive compensation plan in place for management level. In 2003, an EICP for employees in former salary grades 18 and below (typically individual contributors in technical, professional, or support roles) was initiated. Base pay levels were not reduced for these employees at the time the plan was implemented. This was due to the fact that at the time the plan was implemented, total compensation, which is base salary and annual incentive, was slightly below the 50th percentile (median) point of survey results. The Company targets pay levels of plus or minus 5.0% of market median. The Company's pay level, including the additional incentive, continues to be within this range.

Q. Is there an alternative to providing incentive pay for salaried employees?

A. The alternative would be to increase the base compensation to a level that approximates the overall competitive market level of compensation. Absent the higher base pay, Consumers Energy's compensation offering would not be competitive with the labor market. For example, if the base target were $50,000 for a hypothetical job and market-based average pay was $50,000 plus a $2,000 incentive award, then the Company

would need to offer $52,000 to match the market's current pay. So, the alternative to having an incentive component of overall compensation would be to raise base pay to the market's overall compensation. Eliminating incentive pay would result in the same compensation costs, but employees would lose focus on continuous improvement, safety, quality, cost, reliability, and delivery to the customer. Increasing base pay would also result in a higher level of fixed costs tied to base pay, such as certain pension and defined contribution benefit plans, life insurance, disability insurance, and other salary-based employee benefits.

The Company's overall compensation needs to be comparable to the market for salaried employees regardless of whether it is composed of only base pay or composed of base pay plus the target incentive award amount. The Company has maintained overall compensation at competitive levels through base pay plus the target incentive award amount.

Q. Would elimination of incentive pay be in the best interests of customers?

A. No. With incentive compensation, the employees and the Company must re-earn the at-risk compensation each year. If high levels of performance are not met each year, incentive pay can be reduced or eliminated. The elimination of variable "at risk" pay would create a situation where all compensation is guaranteed and would remove an important incentive to improve service. This result would be counter to customer interests. The elimination of variable "at risk" pay would create a situation where compensation would be below market competitive levels. Competitive pay is needed to attract and retain the high-quality talent required to deliver exceptional service to customers. It would be difficult to achieve the Company's purpose of world-class performance delivering hometown service without the

right talent. The knowledge, skills, and abilities of Consumers Energy's employees are key determinants in the quality and timeliness of service that customers receive. Our ability to deliver what customers expect such as reliable and safe energy delivery, on-time completion of service orders, and energy savings depends upon having the right talent in the right job at the right time. Having incentive compensation that is structured around goals that provide benefits to customers is in the best interest of the customer.

Q. How does the Company determine the level of overall compensation for officers?

A. A utility must maintain a competitive total compensation package to attract and retain executive talent. As discussed above, Consumers Energy creates a compensation package for officers that delivers base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50th percentile of the market, as defined by a Compensation Peer Group approved by the Compensation Committees of the Boards of Directors. The Compensation Peer Group consists of energy companies comparable in business focus and size to CMS Energy with which the Company might compete for executive talent. The Compensation Peer Group currently includes 19 companies.

Q. How do you know the market data that you are using for officer compensation are appropriate and are not inflating salary levels?

A. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of a Compensation Peer Group, which it develops based on criteria discussed below, as well as taking into account additional information from published surveys of compensation in the public utility sector and general industry. During the Compensation Committee's review of officers'

compensation levels, consideration is given to the advice and information received from the independent compensation consultant; however, the Compensation Committee is ultimately responsible for determining the form and amount of the compensation programs.

Where available by position, Compensation Peer Group data serves as the primary reference point for pay comparisons of utility specific roles, and broader survey data and published proxy data are also provided by the compensation consultant as a point of reference for utility-specific roles and comparisons of general industry roles. Where available by position, the independent executive compensation consultant of the Compensation Committee, gathers compensation data from Willis Towers Watson's Energy Services Executive Database (over 50 investor-owned utilities) and Willis Towers Watson's General Industry Executive Database (approximately 500 participating companies), which it regresses based on CMS Energy's revenues to provide additional market context to the Compensation Peer Group. In selecting members of the Compensation Peer Group, financial and operational characteristics are considered. The criteria for selection of the Compensation Peer Group included comparable revenue, relevant utility industry group, similar business mix (revenue mix between regulated and non-regulated operations), and availability of compensation and financial performance data.

The survey data indicate that the Company's overall officer compensation levels, assuming the EICP and restricted stock payment at the target market-based level, are reasonable.

In addition, annually, proxy-advisor service companies Glass Lewis & Co. and Institutional Shareholders Services assist institutional investors in their advisory vote on

the reasonableness of compensation pay and practices of the proxy-named executive officers by providing a vote recommendation. The incentive pay practices for the proxy-named executive officers are the same as for the remaining officer group. In 2024, both proxy advisory service firms recommended a vote "for" the proxy-named executive officer compensation pay and practices. Also, shareholders voted 95% in favor to approve executive compensation as described in the 2024 Proxy Statement which is above the S&P 500 average of 92%.

Q. Is survey data information for the third-party consultant proprietary information?

A. Yes. Consumers Energy's Compensation Committees engages an independent third-party consultant to provide information regarding officer compensation practices of the Compensation Peer Group as well as additional information from Willis Towers Watson published surveys of compensation in the public utility sector and general industry.

The Willis Towers Watson survey sources used by Pay Governance are produced solely for use by database participants and are maintained by Willis Towers Watson in connection with the participant's own internal human resources management department. The surveys are the confidential and proprietary work product of Willis Towers Watson, which owns all related intellectual property rights. Pay Governance has written consent from both Willis Towers Watson and CMS Energy to use the surveys on CMS Energy's behalf. Pay Governance is prohibited from using or reproducing the database and survey reports prepared by Willis Towers Watson.

Q. Is the Company able to provide the survey data?

A. No. The market median information the Company utilizes is confidential, proprietary, and commercially sensitive data belonging to third parties. Consumers Energy is contractually prohibited from sharing this information.

Although the Company is prohibited from sharing the market data used in setting compensation for its top five officers, the Company recognizes that it could be helpful to have access to some market data to evaluate the reasonableness of the compensation included in rates for the Company's top five officers. Therefore, the Company compiled and provided non-confidential market data using the following compensation elements from the Compensation Peer Group's publicly filed proxy statements: salary, stock awards, and non-equity incentive. See Exhibit A-74 (AMC-4).

Because this market data uses only publicly available non-proprietary information, it does not perfectly represent the information that the Company used to benchmark and assist the Compensation Committee to determine compensation for Consumers Energy's top five officers. However, that does not support the conclusion that it is inadequate to support the level of compensation for the Company's top five officers. First, the proprietary benchmarking information alone does not mechanically decide how compensation will be set. When making pay adjustments, the Compensation Committee considers the CEO's recommendations, along with proprietary Compensation Peer Group data, internal equity, tenure, and other proprietary market data from surveys provided by the independent compensation consultant. Actual compensation decisions are based on the following as described on page 21 through page 24 of my testimony. Second, the data provided in Exhibit A-74 (AMC-4) is sufficiently consistent with the proprietary data that

it does allow for a valid comparison of the compensation of the highest paid through the 2nd, 3rd, 4th, and 5th highest paid named officers compared to the Company's compensation peer group.

Q. Does the independent consultant provide other services for CMS Energy or Consumers Energy that could result in a conflict of interest?

A. No. The independent consultant is required to obtain approval of the Compensation Committee of the Boards of Directors before undertaking any activity on behalf of the management of CMS Energy or Consumers Energy. During the time the consultant has been engaged as the compensation consultant for the Boards of Directors, it has not performed any services on behalf of the management of CMS Energy or Consumers Energy. The independent consultant is hired by and serves the Compensation Committee; it is not hired by or providing services to CMS Energy or Consumers Energy.

Q. Are surveys the only determining measure used in setting officer compensation levels?

A. No. Additionally, the Compensation Committee considers experience levels and individual contributions of the respective officers.

Q. Are incentive plans for officers common in the utility industry or in other industries?

A. Yes, incentive plans are prevalent. Research from Mercer, U.S. Compensation Planning 2014/2015 survey indicates that approximately 96.0% of companies, and 98.0% of energy companies, offer annual incentive (variable pay) programs for officers. The survey data support the conclusions that including incentive pay as part of a competitive pay package is a standard practice and is required to attract and retain qualified officers.

III. INCENTIVE COMPENSATION PLANS

A. Description of Incentive Plans

Q. Please describe the EICP that is in place for 2024.

A. The EICP for 2024 is based on achieving performance goals related to critical areas of the Company's operations. The goals focus on continuous improvement measures and maintaining financial health to deliver value benefits to customers (not seeking recovery of financial goals in this case). The Company's EICP goals seek to encourage employees to provide reliable energy, customer value, and responsive service to customers, and to do so safely. Each year, the Company establishes utility-specific performance criteria which focus on continuous improvement goals and breakthrough goals. For 2024, there were six specific operational performance measures, and one measure related to being financially healthy. The EICP Operational Performance Measures are summarized on Exhibit A-71 (AMC-1). The 2024 officer and non-officer goals and weighting are shown on page 1 and operational goal targets on page 2.

Q. Please describe Exhibit A-71 (AMC-1).

A. Exhibit A-71 (AMC-1) identifies the operational performance areas that the EICP focuses on and identifies the specific measures that have been adopted for each of these areas. For the 2024 historical year, 50.0% of the non-officer incentive compensation and 30% of officer incentive compensation was based on operational performance. For purposes of this rate case, the Affordability (O&M savings from Waste Elimination) measure associated cost has been removed from the rate request as the Company has determined that it is financial in nature.

Q. Is the structure of the EICP goals for 2025 similar to 2024?

A. The specific performance measures and targets for 2025 are, as in prior years, a combination of measures related to operational performance and financial performance. As indicated above, the Company is not seeking recovery of the financial performance measures in the case. For non-officers, the operational performance and financial health goals will be weighted equally (50% operational and 50% financial). For officers, the operational performance and financial performance measures are weighted 30% operational and 70% financial. The officer operational goals are the same as the non-officer operational goals.

Q. Will the non-officer performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?

A. Yes. Performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. While the number and precise phrasing of operational goals may vary from the historical test year, areas of focus will continue to include safety, reliability, cost, delivery, and customer care.

Q. Will the officer performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?

A. Yes. Operational and financial performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. The operational measures will hold a weighting of 30%, meaning 30% of the officer incentive compensation is based on operational performance (same goals as non-officers) and the

remaining 70% is based on financial performance. As noted above, the Company is not seeking recovery of the financial performance measure in this case.

Q. Please discuss the strategy and process for developing the EICP goals.

A. Company witness Meschke provides a discussion of the strategy and process for developing the EICP goals.

Q. Why has the Company's management chosen to design the EICP with broad goals and objectives on a Company-wide basis rather than individual goals and objectives for individual employees?

A. It is necessary and appropriate for a large organization, such as Consumers Energy, to establish broad goals and objectives that are communicated to all employees as matters that are important to the success of the organization. Some employees will be in a better position to influence whether particular goals and objectives are met, but having every employee linked to a set of common customer-focused objectives is an effective method for emphasizing the importance of customer value and service. Having common goals and objectives (i) provides clear communication of Company goals, (ii) encourages employees to support each other and work together for common goals, and (iii) provides a scorecard with a focus on corporate-wide goals that benefit customers.

Consumers Energy incorporates individual goals through the annual performance feedback process, which includes the creation and review of individual goals and objectives for each salaried employee and the opportunity to recognize and reward individual performance. The existence of a common set of customer objectives enables supervisors and employees to establish individual goals and objectives which are supportive of, and in alignment with, the corporate goals reflected in the EICP.

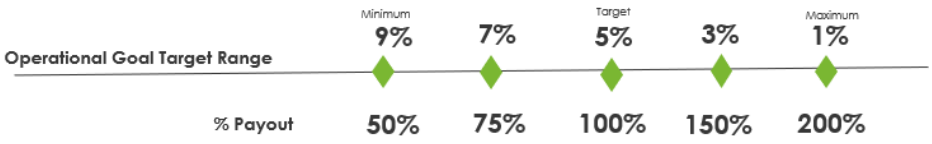
Q. How are the payout levels that are shown on Exhibit A-71 (AMC-1) set?

A. When setting payout levels, threshold is set at a level of achievement that can typically be reached 80% to 90% of the time in a 10-year period. Maximum payout is for exceptional performance (10% to 20% of the time in a 10-year period). These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. Overall compensation levels, including the EICP at target (100%) level that Consumers Energy seeks, are not excessive. It is reasonable for Consumers Energy to pay its employees competitive levels of compensation.

Q. Are the payout levels that are shown on Exhibit A-71 (AMC-1) similar to 2024 and the projected test year?

A. Yes, each operational measure will have its own threshold, target, and maximum for payout. This practice aligns better with market practice and with engaging and motivating performance. Gallup research supports substantial and well-established connections between employee engagement and the achievement of outcomes critical to the business and to customers. See illustration of banded goals below:

Example (Illustration Only):



This structure was in place for 2024 and planned to be in place for the projected test year.

Q. Why are you including both gas and electric performance measures in this plan as this is an electric rate case?

A. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures.

Q. How are the targets for the annual officer EICP incentives measures determined?

A. As mentioned earlier, the goals are the same for the officer and non-officer EICPs, but the weightings are different.

Q. Why is the weighting different for the officer plan?

A. Officer annual incentive awards were based on the achievement of EPS and utility operational goals for the historical test year. As indicated above, the officer plan has a 30% weighting of the same operational goals as non-officers. This strengthens the linkage of officer and non-officer performance while aligning with typical indicators of officer strategy execution through financial goals (weighted at 70%) and corresponding higher weighting.

Q. How are the target amounts for the annual officer incentives determined?

A. The Compensation Committee determines the target amounts of the annual officer incentives. In determining the amount of target incentives, the Compensation Committee considers the following factors:

- The target incentive level and actual incentives paid in recent years;
- The relative importance, in any given year, of each performance goal established; and
- The advice of the Compensation Committee's compensation consultant as to compensation practices at other companies in the Compensation Peer Group and the utility industry.

B. Assessment of Customer Benefits of the Incentive Compensation Plans

Q. What level of expenses for Consumers Energy's incentive plans has been included in the test year revenue requirement?

A. The Company is requesting recovery of electric O&M expenses related to EICP incentive compensation plans at target (100.0%) levels. The following is a listing of the goals illustrated in Exhibit A-72 (AMC-2) for which the Company is requesting recovery:

- **Employee Safety** (OSHA Recordable)
  (Incidents, High Risk Injuries and Zero fatalities)
- **Culture Index**
  (Employee Empowerment, Employee Engagement and DEI)
- **Customer Experience** - Cxi
  (Survey measuring Customer Experience)
- **Electric Reliability** - SAIDI
  (System Average Interruption Duration Index)
- **Methane Emission Reduction**
  (Reduction of Methane Emissions through replacements of Mains and Services, etc.)

The level of expense is approximately $2.2 million as illustrated in Exhibit A-73 (AMC-3).

Q. Please explain Exhibit A-73 (AMC-3), page 2.

A. Exhibit A-73 (AMC-3), page 2, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or a merit increase rate to historical O&M expense. Page 2, column (b), shows the historical O&M expense. Column (c) shows the historical amount that an inflation or labor rate was applied to. Columns (e) and (g) show the amounts to which an inflation rate or labor increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the labor and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b),

(d), (f), (h), and (i). For purposes of incentive expense, only labor increase is applicable. No inflation rate was applied.

Q. How are the electric expenses of $2.2 million related to annual incentive compensation calculated?

A. The $2.2 million for EICP incentive compensation is based on the following:

- For officers: The rate case expense amount is based on 2024 salaries multiplied by the approved target incentive percentage of salary from the 2024 Compensation & Human Resources Committee of the Board of Directors. Factors that impact the incentive expense year-over-year are retirements of officers and successors being at lower incentive amounts (decrease expense), forecasted salary increases (increase expense), and addition of new officers (increase expense) as indicated below.

- For non-officers: The rate case expense amount is based on an estimate of the number of employees in each career stream and job level multiplied by the plan prescribed incentive target amount. Progression to higher job levels as employees gain additional work experience will increase the amount of incentive expense year-over-year and headcount reductions will decrease the amount of incentive expense year-over-year.

Q. How was the electric portion of the incentive compensation expense determined?

A. The allocation percentages were supplied by the Accounting department.

Q. Is a portion of the electric incentive compensation expense allocated between O&M and capital?

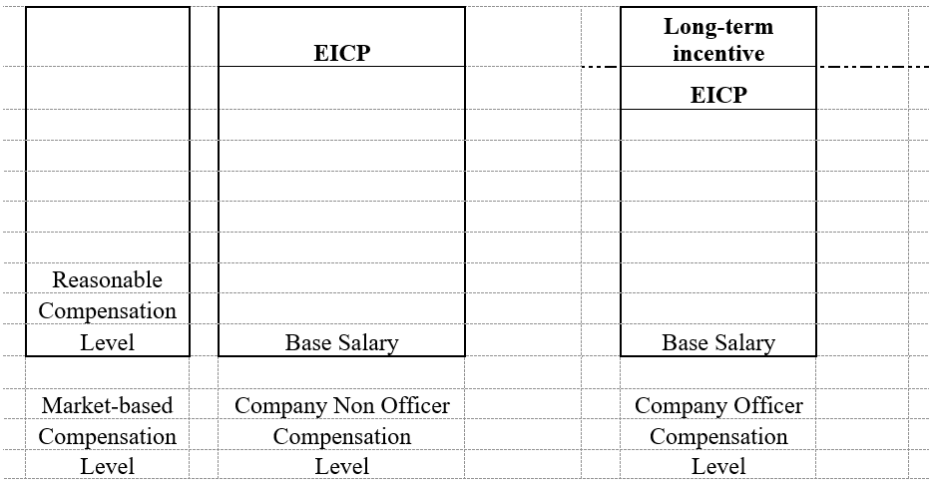
A. Yes. In the Company's 2014 Electric Rate Case, Case No. U-17735, the Commission issued an Order on November 19, 2015, approving the recovery of annual incentive (EICP) in rates for non-officers and non-proxy officers. As a result, in the first quarter of 2016, the Company began classifying annual incentive expense for the approved employee groups as a labor cost. The labor percentages charge between O&M and capital is based on labor studies performed by each business unit for the operational goals portion of the cost. Costs associated with financial performance measures are charged to O&M only.

Q. Do Consumers Energy's electric customers benefit from making a portion of employee compensation subject to incentives?

A. Yes. Paying a competitive level of compensation is an essential prerequisite to being able to attract, retain, and motivate qualified employees. Consumers Energy has determined a reasonable level of compensation and then made a portion of that compensation at risk. Structuring employee compensation so that it includes both base pay and incentive compensation provides motivation for an employee to strive for the total compensation for their position by contributing to the achievement of performance measures. Customers receive both qualitative and quantitative benefits at no additional cost above market-based compensation.

Q. Why do you say there is no additional cost above market-based compensation?

A. The officer and non-officer incentive plans are designed so that the total base salary plus incentive payments will be equivalent to the market-based compensation level. The EICP is part of the overall reasonable level of market-based compensation. It is not in addition to it. This is illustrated in the following diagram:



Q. What is the appropriate standard from a business perspective in evaluating the reasonableness of the EICP costs?

A. Making a portion of compensation subject to incentives is a recognized, well-established, common practice in the utility industry and is reasonable and appropriate. The appropriate standard from a business perspective in evaluating whether the level of compensation is reasonable is whether the *overall* level of compensation, including both base salary and incentive compensation, is reasonable. Using this standard would also be appropriate for ratemaking purposes. Looking at whether the overall level of compensation is reasonable will provide a better indication of whether the incentive plan results in excess rates than attempting to examine the cost allocable to the incentive compensation compared to benefits to customers. The overall level of compensation that Consumers Energy has included in its request in this case is reasonable.

Q. Under the Company's proposal, do shareholders bear a portion of the EICP costs?

A. Yes. The Company's incentive compensation proposal in this case does result in shareholders bearing a portion of incentive costs. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level and for the financial performance measures' cost. Thus, shareholders will absorb any resulting increase in costs arising from above-target performance and for financial measures. If actual payouts in future years are less than target levels due to under performance, then the Company's shareholders will absorb the consequence of underperformance results along with customers. The Company is allocating to

shareholders 100% of the costs of incentive compensation for above-target performance and financial measures.

Q. Is the payment of incentive compensation reasonable given the economic conditions facing the Company's customers?

A. Yes. The incentive compensation costs are reasonable costs of doing business. The market median of survey data reflects current economic conditions and current pay practices. The Company maintains an annual practice of surveying the external market. Any trends in compensation – increases/decreases – would be reflected in the market survey results. Paying a reasonable level of compensation is in the best interests of the Company's customers. Incentive compensation does not result in excessive compensation and is reasonably necessary to attract, retain, and motivate a talented workforce to serve customers. Further, gaps between the skills that employers require and those available in the labor market are growing. Paying a reasonable level of compensation which includes incentive compensation is necessary to attract, retain, and motivate a talented workforce. As of December 2024, the unemployment rate was 5.0% in Michigan and 4.1% nationally, according to the Bureau of Labor Statistics ("BLS"). In addition, BLS data show that there are more job openings in the United States than there are unemployed people. The war for talent is real, and the Company must offer a compelling value proposition to attract and retain the talent required to realize our Company purpose of world-class performance delivering hometown service.

Q. Is the EICP a bonus or profit-sharing plan?

A. No. The EICP is not a bonus or profit-sharing plan. A bonus is a discretionary payment given without predetermined goals or objectives and a profit-sharing plan entitles

employees to a share of the profits of the Company without pre-determined goals or objectives and is not part of total cash compensation market levels. Consumers Energy offers incentive compensation, which is based on predetermined goals and objectives and award levels. Incentive compensation is part of an employee's overall compensation and not in addition to it, like a bonus or profit-sharing plan. The fact that a portion of compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. Employee compensation is a reasonable cost of doing business. If overall compensation levels are reasonable, then those costs should be recoverable through utility rates.

Q. What are some of the ways the EICP incentives benefit customers?

A. Customers derive benefits by having a portion of compensation shifted to the EICP Program since the goals of the program are in the interests of customers. Customer benefits are achieved without any additional cost to customers since this program has been structured as a "carve out" of the employee's base salary. If the EICP costs had not been allocated to incentive compensation, those costs would need to be recovered as base compensation for Consumers Energy to have a reasonable competitive level of compensation.

Also, customers are best served when Consumers Energy can attract, retain, and motivate talented salaried employees and executives with compensation packages that are competitive and fair. Performance-based incentives (like Consumers Energy's) permit the Company to provide an incentive to accomplish specific annual goals that represent performance priorities for Consumers Energy and its customers. With variable pay, the employee and the Company must re-earn the incentive award every year. If performance

goals are not achieved, cash compensation is reduced or eliminated. Variable pay creates a performance culture rather than an entitlement culture.

In addition, an incentive program structured to focus employee attention on operational performance results in both qualitative and quantitative customer benefits. Among other things, customers benefit from increased cyber security, reliability, and on-time delivery and the focus on employee and public safety that helps reduce potential increased costs.

A quantitative analysis of the benefits received by the customer as a result of the EICP is discussed by Company witness Meschke in her direct testimony in this case.

Q. Has Consumers Energy assessed whether benefits to customers of this program equal or exceed costs?

A. Yes. The performance measures provide appreciable benefits to customers. The costs of the EICP are projected at approximately $2.2 million for the test year. The quantifiable electric benefits illustrated in Company witness Meschke's direct testimony are $3.6 million, which shows that the benefits to customers of the Company's EICP Program outweigh the costs of the program. Since this amount is part of the overall level of reasonable compensation, rather than being in addition to it, all benefits to customers are achieved at zero additional cost to customers. Achievement of the Company's EICP goals and objectives result in pay that is competitive with the labor market, not above the market. The EICP costs are not in addition to the reasonable level of compensation, they are part of the reasonable level of market-based compensation. If these amounts are not paid, then overall compensation would be at a level which is below the market level. There is no valid basis to eliminate incentive costs from the cost of service recovered in rates because

they are a part of an incentive plan rather than including these costs as part of base pay. As stated before, overall levels of compensation are at levels that are not excessive. Rate recovery of 100.0% should be allowed.

IV. CONCLUSION

Q. Is the Company's overall compensation program, including the customer-focused incentive, reasonable?

A. Yes. The approach used by the Company is a reasonable approach, is consistent with industry standards, and represents well-established best practices for creating customer focus through compensation design, and it does so without any additional customer cost above the market. The overall compensation levels are reasonable relative to the market, are determined in a reasonable manner, and are a reasonable cost of doing business. Compensation is structured in a manner that rewards improved operational and financial performance that benefits customers. The incentive compensation costs should, therefore, be included in the cost of service recovered from customers. These are legitimate and reasonable costs of doing business. Rates established in this rate case should include approximately $2.2 million for incentive compensation expense.

Q. Please summarize reasons why full recovery of incentive compensation costs should be allowed in this case.

A. Reasons that full recovery of operational goal incentive compensation costs should be allowed include the following:

- Employee compensation is a reasonable cost of doing business, has been set at a reasonable level, and has been determined using a reasonable methodology;
- The amount of compensation that is subject to incentive measurements is part of the market-based compensation level, not in addition to it;

- The incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce to best serve the customer;

- Making a portion of compensation subject to incentives is a recognized, well-established, and common industry practice and is neither irrational nor unreasonable;

- The decision of Consumers Energy to allocate a portion of overall compensation that would otherwise have been in base pay so that it is subject to incentives does not provide a valid basis to disallow these expenses;

- The plan incorporates operational as well as financial performance goals;

- Quantitative and qualitative customer benefits of having a portion of compensation subject to incentives occur at no additional cost above market-based compensation to customers given the compensation structure adopted;

- Investors, including shareholders, bear the expense of incentive compensation in excess of the target levels and for incentive compensation provided to proxy officers; and

- The focus should be on whether the overall level of compensation is reasonable, not on the precise structure of the compensation program.

It is reasonable for Consumers Energy to pay its employees competitive levels of compensation. Paying employees at competitive market levels is reasonable and prudent. Those incentive pay costs are reasonable costs of doing business and are recoverable from customers.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Amy M. Conrad who previously submitted testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut the direct testimony and exhibits presented by witnesses for the Attorney General and the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") regarding Consumers Energy Company's ("Consumers Energy" or the "Company") incentive compensation plan and the recommendations to exclude incentive compensation costs from the revenue requirement in this case. For the reasons discussed in my direct testimony and in this rebuttal testimony, the Commission should find that the incentive compensation costs linked to operational measures that Consumers Energy is seeking to recover in this case are a reasonable cost of doing business and should be included in rates. Consumers Energy has acted reasonably in paying its employees at market levels. It would be unreasonable not to allow the Company to have that reasonable and appropriate business expense recovered in rates.

Q. How is your rebuttal testimony organized?

A. In Section I of my rebuttal testimony, I address the direct testimony and exhibits presented by Attorney General witness Sebastian Coppola. In Section II, I address the direct testimony and exhibits presented by Staff witness Theresa McMillan-Sepkoski.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

I. REBUTTAL TO ATTORNEY GENERAL WITNESS COPPOLA

Q. At page 178, lines 12 through 13, of his direct testimony, Mr. Coppola states: "Generally, the Company's short-term incentive plans are too heavily weighted toward financial measures that mostly benefit shareholders and not customers." Do you agree?

A. No, the Company is not requesting recovery of any Employee Incentive Compensation Plan ("EICP") dollars in this case related to the financial metrics**.** The Company in this case is seeking recovery only for the incentive costs at target level associated with the operational goals portion of the short-term incentive (EICP) for both non-officers and all officers. Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers.

Q. At page 179, lines 11 through 14, Mr. Coppola states: "Even mediocre performance will be rewarded if only a single metric is achieved. This is a very generous incentive plan that is not directly connected with achieving superior customer benefits before making threshold incentive payouts." Do you agree?

A. No. Employees, as a whole, must re-earn the incentive/at-risk portion of compensation each year. Moving to a banded goals payout for each operational measure sets minimum (thresholds), targets, and maximum payout. The Company is only seeking recovery of target level payout. It is common market practice to use individual goals that set minimums (thresholds), targets, and maximum goals (banded goals) with payout percentages based on level of achievement. Structuring the payout to consider performance of each goal

individually also ensures that employees have an independent motivation to achieve each goal regardless of whether another goal may be off target to meet payout levels during the year. This removes any potential mis-incentive to "give up" on one goal just because another may have become unlikely to be achieved. Each goal has the ability to earn an EICP payout on its own achievement, so every goal remains important and employee motivation to attain each goal individually remains high.

Rewarding employees for the level of achievement aligns pay for performance. Employees know what the minimum level of achievement is to receive a payout and have visibility to what above target rewards they can receive for over achievement. This structure motivates employees to attain the target or goal but still allows for recognition for some below target performance and additional reward for above target performance.

If the threshold to achieve a payout was set at a level viewed as unachievable, it would be difficult to maintain employee motivation and would result in less customer benefits. Overall compensation levels including the EICP are established at a target (100%) level that is not excessive. The incentive compensation portion of the Company's total compensation ensures that employees are provided a reasonable incentive to achieve exceptional performance levels. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level. Thus, shareholders will absorb any resulting increase in costs arising from above target performance.

Q. At page 179, lines 15 through 16, of his direct testimony, Mr. Coppola states: "[T]he fact that the performance measures use CMS Energy financial information and comingle electric and gas business measures is a concern." Do you agree?

A. No. For purposes of efficiency and improved service, the Company has combined operations and structured the incentive goals to deliver customer value through continuous improvement, safety, quality, cost, delivery, morale, and financial performance measures. Performance in these areas is critical for the Company's success in its electric public utility business. For that reason, the incentive plan contains both gas and electric measures. The related incentive expense is then allocated between electric and gas businesses based on multiple factors determined by the Accounting Department based on the type of activities the departments or business units perform. These factors include but are not limited to: (i) percentage of time; (ii) property, plant, and investments; (iii) operating revenue; (iv) headcount; and (v) labor. The quantified benefits relate to overall Company priorities. Both electric reliability and methane emission reduction are essential to the Company's organizational priorities. The Company ensures the EICP is quantified to ensure electric customers pay for the benefits they receive and given the combined Company operations it is reasonable to include both goals in the EICP. The value specifically for electric customers far exceeds the total EICP costs allocated to electric customers.

Q. At page 180, of his direct testimony, Mr. Coppola states: "The Company has indicated that it continues to pay salary increases each year with increases well above the rate of inflation over the last five years". Do you agree?

A. No. For rate making purposes, the Company follows the direction of the Commission's Order in Case No. U-20963 and uses the same inflation factor to adjust both labor and

non-labor expenses for determining projected labor costs. Consumers Energy's compensation is designed to be competitive with what is seen in the labor market including rewarding and motivating talent rather than trying to keep up with inflation.

Q. At pages 180 through 182 of his direct testimony, Mr. Coppola discusses various reasons that he disagrees with the Company's request to recover incentive compensation costs in rates. Do the concerns and issues he has identified in his direct testimony provide a valid basis to not allow any recovery of incentive compensation costs in rates?

A. No. I disagree with his analysis and his conclusions. Mr. Coppola's conclusion that Consumers Energy's incentive compensation plans do not benefit customers is not correct. A wide body of research supports the view that, when properly selected and implemented, as has been done with the Consumers Energy plans, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. The overall compensation levels are reasonable. The incentive compensation is part of the overall reasonable compensation level, not an addition to it.

Q. At page 183 of his direct testimony, Mr. Coppola states that "the average achievement rate for the past five years was 66%." Do you agree?

A. No. I disagree with his analysis and his conclusions. The EICP operational payouts averaged 105% as illustrated in Part III_086 (years 2020 through 2023) and U21870-AG-CE-0672_Conrad_ATT_1 (2024) and shown in the table below:

Performance Year	Operational Goal Payout %
2020	125%
2021	75%
2022	109%
2023	94%
2024	124%
5 Year Average	105%

The Company is requesting recovery of target level payout for operational measures only. When setting payout levels, the threshold is set at a level of achievement that can typically be reached 80 to 90% of the time in a ten-year period. Maximum payout is for exceptional performance (10% to 20% of the time in a 10-year period). These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal.

II. REBUTTAL TO STAFF WITNESS MCMILLAN-SEPKOSKI

Q. What is the pay process for officer incentive targets?

A. As stated on page 21 of my direct testimony, Consumers Energy creates a compensation package for officers that delivers base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50th percentile of the market, as defined by a Compensation Peer Group approved by the Compensation Committees of the Boards of Directors. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of a Compensation Peer Group.

Q. Is survey data information for the third-party consultant proprietary information?

A. Yes. Consumers Energy's Compensation Committees engage an independent third-party consultant to provide information regarding officer compensation practices of the Compensation Peer Group as well as additional information from Willis Towers Watson published surveys of compensation in the public utility sector and general industry.

The Willis Towers Watson survey sources used by Pay Governance are produced solely for use by database participants and are maintained by Willis Towers Watson in connection with the participant's own internal human resources management department. The surveys are the confidential and proprietary work product of Willis Towers Watson, which owns all related intellectual property rights. Pay Governance has written consent from both Willis Towers Watson and CMS Energy to use the surveys on CMS Energy's behalf. Pay Governance is prohibited from using or reproducing the database and survey reports prepared by Willis Towers Watson.

Q. Is the proprietary nature of officer compensation the reason the Company did not provide Staff with the compensation level of the top five officers compared to market median referenced in Staff Exhibit S-9.2?

A. Yes. As illustrated in the Company's response shown in Staff Exhibit S-9.2, the market median information requested is confidential, proprietary, and commercially sensitive data belonging to third parties. Consumers Energy is contractually prohibited from sharing this information.

Although the Company is prohibited from sharing the market data used in setting compensation for its top five officers, the Company recognizes that it could be helpful for Staff to have access to some market data to evaluate the reasonableness of the

compensation included in rates for the Company's top five officers. Therefore, the Company compiled and provided non-confidential market data using the following compensation elements from the Compensation Peer Group's publicly filed proxy statements: salary, stock awards, and non-equity incentive.

Because this market data uses only publicly available non-proprietary information, it does not perfectly represent the information that the Company used to benchmark and assist the Compensation Committee to determine compensation for Consumers Energy's top five officers. But, that does not support the conclusion that it is inadequate to support the level of compensation for the Company's top five officers. First, the proprietary benchmarking information alone does not mechanically decide how compensation will be set. When making pay adjustments, the Compensation Committee considers the CEO's recommendations, along with proprietary Compensation Peer Group data, internal equity, tenure, and other proprietary market data from surveys provided by the independent compensation consultant. Actual compensation decisions are based on the following as described on page 22 through page 26 in my testimony. Second, the data provided in Exhibit A-74 (AMC-4) is sufficiently consistent with the proprietary data that it does allow Staff to see a valid comparison of the compensation of the highest paid through the 2nd, 3rd, 4th, and 5th highest paid named officers compared to the Company's compensation peer group. As Staff indicated, it was able to review the proprietary Pay Governance report under the following conditions set forth by the proprietary owners, Pay Governance:

> That it will review these materials in the presence of an appropriate representative of CMS and shall keep these extracts strictly confidential and shall not copy or distribute these extracts to any other party, shall use them solely for the purpose of this inquiry and shall exempt Pay Governance

from public disclosure under any other inquiry or applicable freedom of information or open records acts.

As the owner of the reports, these were the conditions Pay Governance set forth. The report contained the same data shared with the Compensation Committee of the Board for their decision making on officer compensation.

Q. Do you agree with Staff's recommendation to exclude the top five officer operational goal annual incentive expense?

A. No. As stated above, having the officers hold specific operational measures provides a stronger linkage to Company operational incentive priorities that support customer benefits. This is a result of the addition of 30% of officer pay directly linked to operational measures. Starting in 2022, the officer operational goal modifier was removed, and the operating cash flow measure was replaced with the same operational measures as non-officers with a weighting of 30%.

In previous cases, the Company regarded the work performed by the top five officers as focused broadly across the entire CMS Energy enterprise; however, in light of the move to a 30% weighting on Consumers Energy-specific operational measures for EICP, we now have a measurable component of their compensation linked directly to work on behalf of the utility and to operational outcomes that benefit customers. Under the Company's current proposal in this case, shareholders continue to bear 100% of the cost of incentive compensation for financial measures and above target operational measure performance.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Thank you, Your Honor.

Next we have company witness, Patrick Daly, I will note that, Mr. Daly's direct testimony was originally filed a confidential version and a redacted version, that the company will be filing all of Mr. Daly's testimony into the public record and that direct testimony consisted of a cover page and 40 pages of questions and answers. Mr. Daly also had revised rebuttal testimony consisting of a cover page and 12 pages of questions and answers. Mr. Daly also had several exhibits, they are Exhibit A-1 Schedule A-1, A-1 Schedule A-2, A-2 Schedules B-1 through B-6, Exhibit A-3, Schedule C-1 through schedule C-50. Sorry. Also schedule Exhibit A-3, Schedule C-5.1, Schedule C-6, Schedule C-7, Schedule C-8, Schedule C-9, Schedule C-10, Schedule C-11, Schedule C-12, and Schedule C-13. Mr. Daly also had Exhibit A-4 Schedule D-1 through Schedule D-5. Mr. Daly also sponsored Exhibit A-11 Schedule A-1 through Schedule A-3, A-12 Schedule B-1 through Schedule B-5. I will note that A-12 does have other witnesses sponsoring that one, Your Honor, so we'll hold that one until the remaining witnesses are bound in. Mr. Daly also sponsored Schedule Exhibit A-13, Schedule C-1, C-1.1, C-2, C-3, C-4, C-5, C-5.1, and C-6 through C-13. Mr. Daly also had Exhibits A-75, A-76, A-77, A-78, A-79, A-80, A-81, A-82, A-83, A-84, A-85, and A-86. I will note that Exhibit A-86 was originally filed as

confidential, but the company will be submitting that exhibit as public as well. And then Mr. Daly had a revised exhibit A-208, A-209, A-210, A-211, A-212, revised Exhibit A-213, revised Exhibit A-214, A-215, revised Exhibit A-216, revised Exhibit A-217. I believe that does it for Mr. Daly.

THE COURT: Did you mention A-215, or did you go right to A-216?

MR. GENSCH: I -- I don't know if I mentioned it, but I meant to mention it. So A-215 too, Your Honor.

THE COURT: No, you may have. I -- I was questioning whether I missed it and just the clarification of the -- other than A-12 which you made reference to, are all of the other exhibits that you mentioned with schedules, are those schedules the entirety of the schedules for those particular exhibits?

MR. GENSCH: Yes, Your Honor, they are.

THE COURT: All right. And just to make sure, if you can confirm that I have it right I have those exhibits as being A-1, A-2, A-3, A-4, A-11, A-13, A-75 through A-86, is that correct?

MR. GENSCH: Yes. Then plus the rebuttal.

THE COURT: Yes. Yes.

MR. GENSCH: Yeah.

THE COURT: All right. Thank you. Are there any objections to the admission of this testimony or these

exhibits?

Hearing none. The direct and rebuttal, revised rebuttal testimony of Patrick Daly are bound into the public record and Exhibits A-1, A-2, A-3, A-4, A-11, A-13, A-75 through A-86 are admitted, as are Exhibits A-208 revised, A-209 through A-12, A-213 revised, A-214 revised, A-215, A-216 revised, and A-217 revised are admitted.

(At 2:53 p.m., Exhibits A-1, A-2, A-3, A-4, A-11, A-13, A-75 through A-86, Exhibits A-208 revised, A-209 through A-12, A-213 revised, A-214 revised, A-215, A-216 revised, and A-217 revised are admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

PATRICK D. DALY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Patrick D. Daly, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Revenue Requirements.

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Economics & Management from Albion College in 2007 and Master of Science in Accountancy degree from Western Michigan University's Haworth College of Business in 2008. I am also a Certified Public Accountant licensed in the state of Michigan.

Q. Please describe your professional experience.

A. From 2008 to 2017, I practiced public accounting with the accounting firm PwC with a focus on performing financial statement and internal control audits for companies within the power and utility industry. I progressed through several levels of increasing responsibility during this time, achieving the position of Senior Manager in July 2017. In 2018, I transferred to PwC's management consulting practice again with a focus in the power and utility industry.

In April 2019, I joined DTE Energy as a Principal Financial Analyst in the Accounting Policy & Research organization. My responsibilities included, among other things, determining the appropriate accounting for major transactions, and the implementation of new accounting standards. In April 2022, I accepted a position in DTE's Regulatory Accounting & Strategy organization. My responsibilities included assisting

with the development and management of regulatory accounting policies and practices as well as supporting regulatory filings. I also had responsibility for analyzing the accounting implications of new legislation and Michigan Public Service Commission ("Commission" or "MPSC") orders and supporting expert testimony on accounting issues and financial projections in various proceedings before the MPSC. I joined Consumers Energy as Director of Revenue Requirements in July 2024.

Q. What are your responsibilities as the Director of Revenue Requirements at Consumers Energy?

A. As the Director of Revenue Requirements, I am responsible for managing and preparing the following: (i) studies related to the level of the Company's revenue requirements, including the preparation, coordination, and monitoring of electric and gas general rate case filings before the Commission; and (ii) other financial analyses.

Q. Have you previously filed testimony with the MPSC?

A. Yes. I filed testimony in the following case:

Case No. U-21338 DTE Electric Company 2023 Securitization

Q. What is the purpose of your direct testimony in this proceeding?

A. In my direct testimony, I will cover the following topics: (i) the Company's revenue deficiency calculation for the historical year; (ii) the Company's revenue deficiency calculation for the projected test year; (iii) requests related to distribution capital deferrals; and (iv) the projected test year revenue requirement for the Demand Response ("DR") Programs. In addition, I will request regulatory asset treatment for the Company's proposed ramp-up to its Low Voltage Distribution ("LVD") Forestry program expenditures as supported by Company witness Sara E. Stewart. Finally, I describe the amounts included for recovery in this case related to the SAP S/4HANA Implementation Project ("SAP

S/4HANA Project") and request the deferral of related operating and maintenance ("O&M") expense and an adjustment to the amortization period of the cloud implementation costs for the software as a service ("SaaS") solutions associated with the project.

Q. How is your direct testimony organized?

A. My direct testimony is organized in sections consistent with the topics I will be covering:

SECTION I: HISTORICAL YEAR

SECTION II: PROJECTED TEST YEAR

SECTION III: REGULATORY ASSETS AND OTHER ACCOUNTING TREATMENT

SECTION IV: DISTRIBUTION DEFERRAL

SECTION V: DEMAND RESPONSE

Q. How does the Company present the historical and projected revenue deficiency calculations?

A. The Company presents the historical and projected revenue deficiency calculations in compliance with the Commission's Standard Filing Requirements that were approved in Case No. U-18238.

Q. Please describe the revenue requirements determination.

A. My direct testimony presents the revenue deficiency for the actual historical period. Additionally, my direct testimony presents and explains how the revenue deficiency for the future projected test year was developed. I will also reconcile the historical and projected test year periods. Through this filing, the Company demonstrates that it requires a rate increase to earn a just and reasonable return.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. The historical test year exhibits are identified in Section I of my direct testimony. The projected test year exhibits are identified in Section II of my direct testimony. In addition, I am sponsoring the following exhibits:

Exhibit A-82 (PDD-58)	LVD Forestry Ramp-up – Revenue Deficiency Impact of O&M Deferral;
Exhibit A-83 (PDD-59)	Demand Response Revenue Requirement;
Exhibit A-84 (PDD-60)	Distribution Deferral for the projected test year ending February 28, 2025;
Exhibit A-85 (PDD-61)	Distribution Deferral for the projected test year ending February 28, 2026; and
Confidential Exhibit A-86 (PDD-62)	SAP S/4HANA Implementation Project – Revenue Deficiency Impact of O&M Deferral.

Q. Were the exhibits presented in your direct testimony prepared by you or under your direction and supervision?

A. Yes.

I. HISTORICAL YEAR

Q. What is the actual historical year used in the exhibits and supporting testimony?

A. The Company selected the 2024 calendar year as the historical year.

Q. Please identify the exhibits that you are sponsoring associated with the historical year.

A. The following exhibits are being submitted to satisfy the historical test year requirements:

Exhibit A-1 (PDD-1)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2024;
Exhibit A-1 (PDD-2)	Schedule A-2	Historical Financial Metrics – Electric Results Only;
Exhibit A-2 (PDD-3)	Schedule B-1	Rate Base for the Historical Year Ended December 31, 2024;
Exhibit A-2 (PDD-4)	Schedule B-2	Total Utility Plant for the Historical Year Ended December 31, 2024;
Exhibit A-2 (PDD-5)	Schedule B-3	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2024;
Exhibit A-2 (PDD-6)	Schedule B-4	Working Capital for the Historical Year Ended December 31, 2024;
Exhibit A-2 (PDD-7)	Schedule B-5	13-Month Average Balance Sheet for the Historical Year Ended December 31, 2024;
Exhibit A-2 (PDD-8)	Schedule B-6	Point-In-Time Balance Sheet for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-9)	Schedule C-1	Adjusted Net Operating Income for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-10)	Schedule C-2	Calculation of the Revenue Conversion Factor for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-11)	Schedule C-3	Operating Revenue for the Historical Year Ended December 31, 2024;

Exhibit A-3 (PDD-12)	Schedule C-4	Cost of Fuel and Purchased Power for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-13)	Schedule C-5	Operation and Maintenance Expenses for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-14)	Schedule C-5.1	Operation and Maintenance Expenses by Witness for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-15)	Schedule C-6	Depreciation and Amortization Expenses for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-16)	Schedule C-7	General Taxes for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-17)	Schedule C-8	Federal Income Taxes for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-18)	Schedule C-9	State Income Taxes for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-19)	Schedule C-10	Other (or Local) Taxes for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-20)	Schedule C-11	Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-21)	Schedule C-12	Income Tax Effect of Interest for the Historical Year Ended December 31, 2024;
Exhibit A-3 (PDD-22)	Schedule C-13	Interest Synchronization Adjustment for the Historical Year Ended December 31, 2024;
Exhibit A-4 (PDD-23)	Schedule D-1	Capital Structure and Rate of Return Summary for the Historical Year Ended December 31, 2024;

Exhibit A-4 (PDD-24)	Schedule D-2	Cost of Long-Term Debt (Excluding Securitization) for the Historical Year Ended December 31, 2024;
Exhibit A-4 (PDD-25)	Schedule D-3	Cost of Short-Term Debt for the Historical Year Ended December 31, 2024;
Exhibit A-4 (PDD-26)	Schedule D-4	Cost of Preferred Stock for the Historical Year Ended December 31, 2024; and
Exhibit A-4 (PDD-27)	Schedule D-5	Cost of Common Shareholder's Equity for the Historical Year Ended December 31, 2024.

Q. Please discuss the organization and format of the historical period exhibits.

A. The organization and format of the historical period exhibits are specified by the MPSC's filing requirements. The exhibits are organized into schedules that present the development of the revenue deficiency (Schedule A), rate base (Schedule B), adjusted Net Operating Income ("NOI") (Schedule C), and rate of return (Schedule D). Most of the exhibits include the presentation of both a "total electric amount" and a "jurisdictional electric amount." The total electric amounts were converted to jurisdictional electric amounts using the factors from the Commission Order in Electric Rate Case No. U-21389 as they were the factors in effect at the end of the historical test year.

Q. Who is sponsoring the historical year Schedule E exhibits?

A. The historical year Schedule E exhibits are sponsored by Company witness Eugene M. Breuring.

Q. Please describe the Schedule A exhibits for the historical period.

A. Exhibit A-1 (PDD-1), Schedule A-1, is the computation of the electric revenue deficiency for the year ended December 31, 2024. Exhibit A-1 (PDD-2), Schedule A-2, is a multiple page exhibit that provides financial metrics on both a financial basis (pages 1 through 3)

and a ratemaking basis (pages 4 through 6) for the years 2020 through 2024. Pages 1 and 4 calculate an electric earned rate of return on common equity for each of these years. The $2.0 million jurisdictional electric revenue deficiency is shown on Exhibit A-1 (PDD-1), Schedule A-1, line 8. Schedule A-1 is developed from financial data presented in Schedules B, C, and D described below.

Q. Please describe the Schedule B exhibits for the historical period.

A. Exhibit A-2 (PDD-3), Schedule B-1, presents the calculation of average electric rate base for the year ended December 31, 2024 in the jurisdictional electric amount of $14.2 billion as shown on line 7, which is carried forward to Exhibit A-1 (PDD-1), Schedule A-1, line 1. Exhibit A-2 (PDD-4), Schedule B-2, through Exhibit A-2 (PDD-8), Schedule B-6, support the development of the various components of average rate base including net utility plant and working capital.

Q. Please describe the Schedule C exhibits for the historical period.

A. Exhibit A-3 (PDD-9), Schedule C-1, presents the calculation of adjusted NOI for the year ended December 31, 2024 in the jurisdictional amount of $833.6 million, as shown on line 33, which is carried forward to Exhibit A-1 (PDD-1), Schedule A-1, line 2. Exhibit A-3 (PDD-10), Schedule C-2, through Exhibit A-3 (PDD-22), Schedule C-13, support the development of the various components of adjusted NOI. The Schedule C data for the historical period is generally sourced to the Company's 2024 Form P-521 Annual Report to the MPSC.

Q. Please describe the Schedule D exhibits for the historical period.

A. Exhibit A-4 (PDD-23), Schedule D-1, presents the overall rate of return summary for the year ended December 31, 2024. The weighted cost of capital of 5.86% is shown on line 14,

column (h), and is carried forward to Exhibit A-1 (PDD-1), Schedule A-1, line 4. Exhibit A-4 (PDD-24), Schedule D-2, through Exhibit A-4 (PDD-27), Schedule D-5, support the development of various components of the overall rate of return for the historical period including: (i) debt; (ii) preferred stock; (iii) common equity; and (iv) other sources of financing.

Q. Based on your review of the historical year exhibits, was there a revenue deficiency in the historical year?

A. Yes. I have calculated a historical year jurisdictional electric revenue deficiency for the 12-month period ended December 31, 2024, which is presented on Exhibit A-1 (PDD-1), Schedule A-1, as follows:

Jurisdictional	***($ In Thousands)***
Rate Base	$14,241,328
Adjusted NOI	$ 833,578
Overall Rate of Return	5.85%
Required Rate of Return	5.86%
Income Required	$ 835,097
Income Deficiency (Sufficiency)	1,519
Revenue Multiplier	1.3381
Revenue Deficiency (Sufficiency)	$ 2,033

Q. Do the above results include typical ratemaking adjustments such as weather; unusual, one-time, or out-of-period items; and regulatory disallowances?

A. Yes. The historical year presentation begins with the Company's booked results, then ratemaking adjustments and normalizations are recognized, where appropriate, as summarized on Exhibit A-3 (PDD-9), Schedule C-1. I will describe the adjustments and

normalizations in the second part of my direct testimony, which covers the projected test year.

II. PROJECTED TEST YEAR

Q. What projected test year has the Company used in this case?

A. The Company selected the 12 months ending April 30, 2027 as the projected test year in this proceeding.

Q. Please identify the exhibits that you are sponsoring to comply with the Commission's filing requirements related to the projected test year.

A. The following exhibits are being submitted to support and satisfy the projected test year Filing Requirements:

Exhibit A-11 (PDD-28)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-11 (PDD-29)	Schedule A-2	Financial Metrics – Ratemaking Basis – For the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-11 (PDD-30)	Schedule A-3	Comparison of the Historical and Projected Revenue Requirement for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-12 (PDD-31)	Schedule B-1	Rate Base for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-12 (PDD-32)	Schedule B-2	Total Utility Plant for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-12 (PDD-33)	Schedule B-3	Depreciation Reserve and Other Deductions for the Projected 12-Month Period Ending April 30, 2027;

Exhibit A-12 (PDD-34)	Schedule B-4	Working Capital Summary for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-12 (PDD-35)	Schedule B-5	Capital Expenditures Summary for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-36)	Schedule C-1	Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-37)	Schedule C-1.1	Development of Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-38)	Schedule C-2	Calculation of the Revenue Conversion Factor for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-39)	Schedule C-3	Operating Revenues for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-40)	Schedule C-4	Cost of Fuel and Purchased Power for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-41)	Schedule C-5	Operating and Maintenance Expenses for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-42)	Schedule C-5.1	Summary of Inflation and Merit Increases Included in Operation and Maintenance Expenses for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-43)	Schedule C-6	Depreciation and Amortization Expenses for the Projected 12-Month Period Ending April 30, 2027;

Exhibit A-13 (PDD-44)	Schedule C-7	General Taxes for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-45)	Schedule C-8	Federal Income Taxes for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-46)	Schedule C-9	State Income Taxes for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-47)	Schedule C-10	Other (or Local) Taxes for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-48)	Schedule C-11	Allowance for Funds Used During Construction for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-49)	Schedule C-12	Income Tax Effect of Interest for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-13 (PDD-50)	Schedule C-13	Interest Synchronization Adjustment for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-75 (PDD-51)		Regulatory Asset and Amortization Expense of the PowerMiDrive and PowerMiFleet for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-76 (PDD-52)		Regulatory Asset and Amortization of Karn and Campbell Plant Retention and Separation Costs for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-77 (PDD-53)		Regulatory Asset and Amortization Expense of the Net Book Value of Campbell Plant 1, 2 , and 3 for the Projected 12-Month Period Ending April 30, 2027;

Exhibit A-78 (PDD-54)	Regulatory Asset and Amortization Expense of Karn and Campbell Decommissioning Costs for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-79 (PDD-55)	Regulatory Asset and Amortization Expense of the Karn, Campbell, and Classic 7 Ash Disposal Costs for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-80 (PDD-56)	Regulatory Asset and Amortization Expense of the Pension and OPEB Volatility Mechanism, for the Projected 12-Month Period Ending April 30, 2027; and
Exhibit A-81 (PDD-57)	Campbell Regulatory Asset – Return On for the Projected 12-Month Period Ending April 30, 2027.

Q. Please discuss the organization and format of the projected test year exhibits.

A. The projected test year exhibits are organized and formatted in a similar fashion to the historical period exhibits. The exhibits are organized into schedules that present the development of the revenue deficiency (Schedule A), rate base (Schedule B), and adjusted NOI (Schedule C). Company witness Marc R. Bleckman is sponsoring schedules that address rate of return (Schedule D). Company witness Breuring is sponsoring sales, load, and customer data (Schedule E) exhibits. Company witness Emily A. Davis is sponsoring the cost-of-service study. Company witness Laura M. Connolly is sponsoring present and proposed revenue. Company witness Brittani A. Gray is sponsoring the proposed tariff sheet (Schedule F) exhibits.

Q. Please summarize the key findings for the projected test year exhibits.

A. Exhibit A-11 (PDD-28), Schedule A-1, presents the projected jurisdictional electric revenue deficiency for the 12-month period ended April 30, 2027, as follows:

	($ In Thousands)
Rate Base	$15,367,518
Adjusted NOI	707,746
Overall Rate of Return	4.61%
Required Rate of Return	6.35%
Income Required	$ 975,589
Income Deficiency (Sufficiency)	267,843
Revenue Multiplier	1.3381
Revenue Deficiency (Sufficiency)	$ 358,395
Return On – Campbell Regulatory Asset	77,486
Total Revenue Deficiency (Sufficiency)	$ 435,881

Q. Why is the jurisdictional electric revenue deficiency for the projected test year the same as the Total Company projected revenue deficiency?

A. The total Company revenue deficiency for the projected test year is considered 100% jurisdictional. Currently, there is only one contract treated as non-jurisdictional. The contract utilizes the General Meter Lighting tariff rate for all charges on the bill, except for a two-mil discount on the energy charge. While this contract remains in place, the Company has included its projected revenues and the value of the discount as miscellaneous revenues in the instant case.

Q. What inflation factors is the Company using in its presentation?

A. The Company is using inflation factors of 2.10% for 2025, 2.40% for 2026, and 2.40% for 2027,[1] as forecasted by S&P Global Market Intelligence and reported in the November

[1] 0.8% for 4-month proration

2024 edition of its publication *U.S Economic Outlook*. S&P Global Market Intelligence is a leader in economic and financial analysis, forecasting, and market intelligence.

Q. Has the Company provided a summary of where these inflation factors have been used in the case?

A. Yes. Exhibit A-13 (PDD-42), Schedule C-5.1, provides a summary of the inflation included in Other O&M Expenses in the case.

Q. How has Consumers Energy addressed the MPSC's filing requirement to reconcile the projected test year to the most recent calendar year?

A. The following is a list of exhibits that reconcile the projected test year to the historical:

i. Exhibit A-11 (PDD-30), Schedule A-3;

ii. Exhibit A-12 (PDD-34), Schedule B-4;

iii. Exhibit A-13 (PDD-37), Schedule C-1.1; and

iv. Exhibit A-13 (PDD-41), Schedule C-5.

Q. Please explain Exhibit A-11 (PDD-29), Schedule A-2.

A. This exhibit provides the financial metrics and statistics for the projected test year as required by the MPSC's filing requirements. Column (b) shows the metrics assuming no rate relief is granted. Column (c) shows the metrics assuming the Company's full rate relief request is granted.

Q. Please explain Exhibit A-11 (PDD-30), Schedule A-3.

A. This exhibit presents the projected test year revenue deficiency for Consumers Energy of $435.9 million (line 11, column (f)). Column (d) of the exhibit presents pertinent rate base and rate of return amounts for the historical period. Column (e) shows the changes resulting from adjustments supported by the various Company witnesses that were made

in developing the projected test year revenue deficiency. Column (f) then displays the projected test year rate base, income requirement, and revenue requirement.

Q. What are the major differences between the historical year and the projected test year results shown on Exhibit A-11 (PDD-30), Schedule A-3?

A. The comparison of historical and projected results in Exhibit A-11 (PDD-30), Schedule A-3, shows that rate base increases by $1.1 billion (line 3) and the rate of return increases from 5.86% to 6.35% (line 4). In addition, the adjusted NOI (line 6) decreases by $125.8 million when moving from the historical year to the projected test year.

Q. Please describe Exhibit A-12 (PDD-31), Schedule B-1.

A. Exhibit A-12 (PDD-31), Schedule B-1, is a summary presentation of the projected test year average rate base of $15.4 billion as shown on line 7.

Q. Please describe Exhibit A-12 (PDD-32), Schedule B-2.

A. Exhibit A-12 (PDD-32), Schedule B-2, presents the total utility plant for the projected test year. The total on line 24 is carried forward to line 1 on Exhibit A-12 (PDD-31), Schedule B-1.

Q. Please describe how the projected test year average plant and related amounts were developed.

A. Utility plant and reserve balances for the projected test year were developed by calculating a 13-month average of the balances as of April 30, 2026 through April 30, 2027. Actual calendar year 2024 balances for construction work-in-progress ("CWIP"), gross plant, and accumulated depreciation were used as the starting point. Projected capital expenditures (including Allowance for Funds Used During Construction ("AFUDC")) and plant additions were added for the calendar year 2025, calendar year 2026, and the first four

months of 2027; followed by adjustments for projected retirements, depreciation expense, cost of removal, and the calculation of the ending balances for CWIP, plant, and the accumulated provision for depreciation.

Q. Did you make any adjustments to the December 2024 balances used as the starting point?

A. Yes. I removed the historical balances for Campbell Units 1, 2, and 3, to incorporate them under the regulatory asset treatment explained in Section III of my direct testimony. I removed the impacts on the historical plant in-service, construction work in progress, and accumulated depreciation balances of calendar year 2024 expenditures associated with the Company's River Hydro investments. As explained by Company witness Heidi J. Myers, the Company is proposing to extend the hydro revenue requirement deferral approved in Case No. U-21585. The removal of the 2024 hydro expenditures is required because this deferral began in 2024.

Q. Please describe Exhibit A-12 (PDD-33), Schedule B-3.

A. Exhibit A-12 (PDD-33), Schedule B-3, presents the projected depreciation reserve for the projected test year by functional group. The total on line 17 is carried forward to line 2 on Exhibit A-12 (PDD-31), Schedule B-1. The increase in the projected accumulated depreciation provision for the projected test year incorporates depreciation expense calculated using book depreciation rates approved by the Commission in Case No. U-20849. The calculated depreciation expense and associated accumulated depreciation presented also uses depreciation rates for the Ludington Hydro facility approved in Case No. U-20844.

Q. Please explain Exhibit A-12 (PDD-34), Schedule B-4.

A. Exhibit A-12 (PDD-34), Schedule B-4, develops the Company's proposed projected test year balance sheet working capital requirement. The starting point is the 13-month average historical December 2024 working capital shown in column (b). The December 2024 average balances are then adjusted to reflect changes to:

i. Pension and Other Post-Employment Benefits ("OPEB") balances based on projections sponsored by Company witness Kendra K. Grob, and the regulatory asset and liability related to the volatility mechanism;

ii. Accrued tax balances;

iii. Prepaid cloud computing balances sponsored by Company witness Stacy H. Baker;

iv. Regulatory asset balances for PowerMIDrive and PowerMIFleet deferred costs;

v. Regulatory asset balances for D.E. Karn ("Karn") and J.H. Campbell ("Campbell") retention costs, Campbell plant's net book value, and various coal plants' decommissioning and ash disposal costs;

vi. Cash balance sponsored by Company witness Bleckman; and

vii. Deferred debits for a software implementation deferral sponsored by Company witness Baker.

Q. Why did the Company use the balance sheet approach in determining the working capital requirement?

A. Use of the balance sheet method was mandated by the Commission in Case No. U-7350. The Commission, in Case No. U-15895, also required that this method be used to develop the allowance for working capital.

Q. Please describe Exhibit A-12 (PDD-35), Schedule B-5.

A. Exhibit A-12 (PDD-35), Schedule B-5, provides a summary of capital spending as supported by various Company witnesses. This exhibit provides capital spending for the

bridge year and projected test year as well as the projected and approved spending during the previous rate case test year in Case No. U-21585.

Q. Please describe Exhibit A-13 (PDD-36), Schedule C-1.

A. Exhibit A-13 (PDD-36), Schedule C-1, presents the calculation of adjusted NOI for the projected test year of $707.7 million as shown on line 19. Total operating revenues (line 4) are netted against total operating expenses (line 13) to arrive at net operating income on line 14. Further adjustments are made on lines 15, 17, and 18, which utilize normal ratemaking practices to arrive at adjusted NOI on line 19.

Q. Please explain Exhibit A-13 (PDD-37), Schedule C-1.1

A. Exhibit A-13 (PDD-37), Schedule C-1.1, presents the reconciliation of historical year NOI to projected test year NOI. The exhibit presents revenues in columns (c) through (e), expenses in columns (f) through (m), NOI in column (n), AFUDC in column (o), and adjusted NOI in column (p). The exhibit begins with the historical year on line 1, normalizing adjustments to the historical year on lines 2 through 15, and projected test year adjustments on lines 17 through 28. Total adjusted NOI for the projected test year is shown on line 29, column (p). In general, the revenue and expense adjustments are shown with their accompanying tax impacts to arrive at the adjusted NOI. The historical year NOI of $977.9 million on line 1, column (p), ties to the historic NOI on line 17 of Exhibit A-3 (PDD-9), Schedule C-1.

Q. Please explain the normalizing adjustments on Exhibit A-13 (PDD-37), Schedule C-1.1.

A. The adjustments located on lines 2 through 15 are made to comply with prior Commission orders and follow traditional ratemaking adjustments to historical booked results such as:

(i) removing regulatory disallowances; (ii) normalizing for unusual, one-time, or out-of-period items; (iii) bringing certain revenues and expenses "above the line"; (iv) adjusting historical revenues to reflect "normal" weather; and (v) performing related adjustments to income taxes. Additional adjustments include certain O&M expense normalizations to better align the historical year with expected expense amounts in the projected test year. These adjustments are supported by my exhibits and supporting workpapers, and from the exhibits of other Company witnesses.

The historical year adjusted NOI on Exhibit A-13 (PDD-37), Schedule C1.1, line 16, column (p), of $829.5 million, ties to historic NOI on line 33, column (c), of Exhibit A-3 (PDD-9), Schedule C-1.

Q. How were the projected test year adjustments on Exhibit A-13 (PDD-37), Schedule C-1.1, developed?

A. These adjustments represent the movement from the historical year adjusted NOI to the projected test year NOI. The adjustments on lines 17 through 28 are developed from my exhibits and supporting workpapers, and from the exhibits of other Company witnesses. The projected test year NOI on line 29 is the result of netting the projected test year adjustments on lines 17 through 28 against the historical year adjusted NOI on line 16. The projected test year adjusted NOI of $707.7 million on line 29, column (p), ties to the projected test year adjusted NOI on Exhibit A-13 (PDD-36), Schedule C-1, line 19.

Q. Please explain the test year adjustments made for the projected test year on Exhibit A-13 (PDD-37), Schedule C-1.1.

A. Lines 17 through 19 represent the changes in revenues when moving to the projected test year and are supported by Company witness Breuring. Line 20 represents an adjustment

to the power supply costs shown on Exhibit A-13 (PDD-40), Schedule C-4, to align the projected test year Power Supply Cost Recovery ("PSCR") expense with the projected test year PSCR revenues proposed by Company witness Breuring.

Line 21 represents the change in other O&M expenses from the adjusted historical year to the projected test year and are supported by Company witnesses Stacy H. Baker, Richard T. Blumenstock, Jessica R. Byrom, Amy M. Conrad, Matthew J. Foster, Alex M. Gast, Kendra K. Grob, Quenten A. Guinn, Michael P. Kelly, and Sara E. Stewart. The adjustments are detailed on Exhibit A-13 (PDD-41), Schedule C-5 and Exhibit A-13 (PDD-42), Schedule C-5.1.

Line 22 represents the change in the book depreciation expense from the adjusted historical year to the projected test year. The Company used the Commission-approved book depreciation rates, projected capital expenditures, and assumed plant retirements to determine the depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense for the projected test year. The adjustment on line 22 increases depreciation expense from the historical period due to new capital investment.

Line 23 represents an adjustment to real and personal property taxes to the projected test year expense level as supported by Company witness Brian J. VanBlarcum and shown on Exhibit A-13 (PDD-44), Schedule C-7, line 1.

Line 24 represents the change in historical year payroll and other general taxes to the projected test year amount as shown on Exhibit A-13 (PDD-44), Schedule C-7, lines 6 and 15.

Line 25 represents city income tax adjustments to the projected test year level city income tax expense as shown on Exhibit A-13 (PDD-47), Schedule C-10, line 18.

Line 26 reflects the impact of Michigan Corporate Income Tax ("MCIT"). The projected test year MCIT expense is shown on Exhibit A-13 (PDD-46), Schedule C-9, line 20.

Line 27 represents the Federal Income Tax ("FIT") adjustments which result from the other changes in revenue and expense levels for the projected test year. Also reflected are the differences between the FIT expense calculated at the current federal statutory rate and the actual total income tax expense. FIT expense is shown on Exhibit A-13 (PDD-45), Schedule C-8, line 50.

Line 28 represents an adjustment to AFUDC from the adjusted historical year to the projected test year. The projected test year AFUDC is shown on Exhibit A-13 (PDD-48), Schedule C-11. AFUDC is an accounting convention that recognizes the costs, both interest and equity, of financing certain construction projects. The recognition is through the transfer of interest and equity cost from the income statement to CWIP on the balance sheet. The interest and equity costs are capitalized in the same manner as construction labor and material costs when the project is closed to plant-in-service. The criteria for applying AFUDC to a construction project require on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000. AFUDC charged to projects addressing compliance with environmental clean air requirements are not included in this ratemaking adjustment, which is consistent with the Commission's ratemaking treatment. AFUDC increases revenue and NOI, reducing the amount of rate relief requested in the case and is designed to offset the return built into the case for CWIP that is eligible for AFUDC treatment.

Q. Please describe Exhibit A-13 (PDD-38), Schedule C-2.

A. Exhibit A-13 (PDD-38), Schedule C-2, shows the development of the revenue multiplier for the projected test year. The revenue multiplier is a factor that converts a utility's after-tax income deficiency (or sufficiency) into the required change in pre-tax revenue requirement. For the projected test year, the FIT rate is 21.00%, the MCIT rate is 5.24%, and the CIT rate is 0.16%. The resulting revenue multiplier is 1.3381.

Q. Please explain the projected revenues shown on Exhibit A-13 (PDD-39), Schedule C-3.

A. Total projected revenues are shown on line 4. Lines 1, 2, and 3 of the exhibit present the sales, wholesale, and other electric revenues that are supported by Company witness Breuring. The total on line 4 is carried forward to the Company's projected adjusted NOI presentation on Exhibit A-13 (PDD-36), Schedule C-1.

Q. Please explain Exhibit A-13 (PDD-40), Schedule C-4.

A. This exhibit presents the projected test year power supply costs that are supported by Company witness Megan L. Metz. This total is carried forward to line 5 of the Company's projected adjusted NOI presentation on Exhibit A-13 (PDD-36), Schedule C-1.

Q. Please explain Exhibit A-13 (PDD-41), Schedule C-5.

A. Exhibit A-13 (PDD-41), Schedule C-5, presents the other O&M expense for the projected test year as compared to the historical year. The amounts on lines 1 through 23 were provided by Company witnesses Kelly, Stewart, Blumenstock, Guinn, Baker, Byrom, Gast, Grob, Foster, Conrad, and Breuring. These amounts are supported in their respective direct testimony and exhibits. The amounts on line 24 reflect interest expense on security deposits.

Q. Please explain Exhibit A-13 (PDD-42), Schedule C-5.1.

A. Exhibit A-13 (PDD-42), Schedule C-5.1, provides a summary of inflation and labor merit increases included in other O&M expense. Amounts projected using a method other than inflation and merit are included in column (g). As indicated on this exhibit, various Company witnesses provide detailed calculation of the inflation amounts included in this summary exhibit.

Q. Please explain Exhibit A-13 (PDD-43), Schedule C-6.

A. Exhibit A-13 (PDD-43), Schedule C-6, presents the projected depreciation & amortization expense. Depreciation expense is calculated using book depreciation rates approved by the Commission in Case No. U-20849. The calculated depreciation expense and associated accumulated depreciation presented also uses depreciation rates for the Ludington Hydro facility approved in Case No. U-20844. I discuss the calculation of the amortizations in lines 17 through 24 of Exhibit A-13 (PDD-43), Schedule C-6, in Section III of my direct testimony.

Q. Does the Company have a depreciation case pending before the Commission that could impact depreciation expense and therefore, the revenue deficiency in this proceeding?

A. No.

Q. Please explain Exhibit A-13 (PDD-44), Schedule C-7, through Exhibit A-13 (PDD-48), Schedule C-11.

A. These exhibits present the following: (i) projected general taxes; (ii) projected FIT; (iii) projected state income taxes; (iv) projected other (or local) taxes; and (v) projected

AFUDC. The total from each schedule is carried forward to the Company's projected NOI presentation on Exhibit A-13 (PDD-37), Schedule C-1.

Q. Please describe Exhibit A-13 (PDD-49), Schedule C-12.

A. Exhibit A-13 (PDD-49), Schedule C-12, shows the calculation of pro forma interest expense for the projected test year and the corresponding impact on income taxes.

Q. Please describe Exhibit A-13 (PDD-50), Schedule C-13.

A. Exhibit A-13 (PDD-50), Schedule C-13, shows the calculation of the tax effect of the interest synchronization adjustment for the projected test year.

Q. Why are Exhibit A-13 (PDD-49), Schedule C-12, and Exhibit A-13 (PDD-50), Schedule C-13, included in the presentation?

A. The purpose of these exhibits is to align the interest expense and the associated tax benefits in the projected test year with the amount of rate base that is financed with debt and display the alignment in a transparent manner.

III. REGULATORY ASSETS AND OTHER ACCOUNTING TREATMENTS

A. PowerMIDrive and PowerMIFleet Permanent Programs and Pilot Programs

Q. Has the Commission approved deferred accounting treatment for the PowerMIDrive and PowerMIFleet permanent programs and pilot programs?

A. In Case Nos. U-20134 and U-20697, the Commission approved deferred accounting for expenditures associated with the PowerMIDrive and PowerMIFleet pilot programs. The approach adopted by the Commission envisioned a prudency review of actual expenditures after which the amortization expense, based on a five-year amortization to begin the year after the actual expenditures are recorded, would be included in rates. In addition, the Commission allowed for the deferred balance to be included in rate base earning a return

at the authorized rate of return. The Commission also extended this deferred accounting treatment to the permanent programs and reaffirmed the pilot program treatment in its approval of the Settlement Agreement in Case No. U-21224. Most recently, the Commission approved the continuation of the regulatory asset treatment in its final Order in Case. No U-21585.

Q. Please describe Exhibit A-75 (PDD-51).

A. Exhibit A-75 (PDD-51) provides the calculation of the projected test year amortization expense, and the projected test year average regulatory asset balances associated with the PowerMIDrive and the PowerMIFleet Programs.

Q. Describe how the projected test year amortization expense and average deferred balance for the PowerMIDrive program was calculated on Exhibit A-75 (PDD-51).

A. Line 1 provides the actual deferred expenditures for the program through 2024. The program expenditures are supported by Company witness Myrom. Lines 2 through 7 show the amortization expense by year. Line 8 shows the total amortization expense for each calendar year, while line 15 shows the proration for the projected test year ending April 30, 2027. The test year amortization expense of $3.7 million has been included in the projected amortization expense on Exhibit A-13 (PDD-43), Schedule C-6. Line 18 shows the calculation of the average rate base amount for the test year of $8.2 million, which has been included in the projected working capital on Exhibit A-12 (PDD-34), Schedule B-4.

Q. Describe how the projected test year amortization expense and average deferred balance for the PowerMIFleet program was calculated on Exhibit A-75 (PDD-51).

A. Line 9 provides the actual deferred expenditures for the program through 2024. Lines 10 through 13 show the amortization expense by year. Line 14 shows the total amortization

expense for each calendar year, while line 16 shows the proration for the projected test year ending April 30, 2027. The test year amortization expense of $1.8 million has been included in the projected amortization expense on Exhibit A-13 (PDD-43), Schedule C-6. Line 19 shows the calculation of the average rate base amount for the test year of $4.0 million, which has been included in the projected working capital on Exhibit A-12 (PDD-34), Schedule B-4.

B. Karn Units 1 and 2 and Campbell Units 1, 2, and 3 Retention Costs

Q. Please describe Exhibit A-76 (PDD-52).

A. Exhibit A-76 (PDD-52) calculates the projected test year regulatory asset balance and amortization expense for Karn Units 1 and 2 retention costs as ordered by the Commission in Case No. U-20697. The associated working capital and amortization has been included in the case. The $0.2 million average rate base amount for the projected test year has been included in the projected working capital on Exhibit A-12 (PDD-34), Schedule B-4, and the $0.3 million amortization expense has been included in the projected depreciation and amortization expense on Exhibit A-13 (PDD-43), Schedule C-6.

Additionally, this exhibit calculates the projected test year regulatory asset balance and amortization expense for Campbell Units 1, 2, and 3 retention costs as agreed in the Company's Integrated Resource Plan ("IRP) Settlement Agreement in Case No. U-21090, approved by the Commission on June 23, 2022, and most recently in the Order in Case No. U-21585. The $9.6 million average rate base amount for the projected test year has been included in the projected working capital on Exhibit A-12 (PDD-34), Schedule B-4, and the $8.5 million amortization expense has been included in the projected depreciation and amortization expense on Exhibit A-13 (PDD-43), Schedule C-6.

C. Campbell Plant Net Book Value

Q. Why were the Campbell plant balances removed from the calculation of the projected test year average CWIP, gross plant, and accumulated depreciation?

A. The Settlement Agreement approved by the Commission in Case No. U-21090 on June 23, 2022, established that in the next rate case filed after the conclusion of the IRP case (Electric Rate Case No. U-21389), the actual remaining net book value of Campbell Units 1, 2, and 3 would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset. Moreover, the agreement set annual amortization to allow for the recovery of the remaining net book value and the decommissioning costs through May 2031 for costs associated with Campbell Units 1 and 2 and through May 2040 for costs associated with Campbell Unit 3. In addition, the Company is allowed the following:

> (…) to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through the Company's proposed regulatory asset treatment, with a return equal to the Company's weighted average cost of capital ("WACC") premised on the return on equity approved by the Commission in rate cases prior to the retirement date of those units and a 9.0% return on equity after the retirement date of those units, as part of the Company's electric rates over the current design lives of those units. The 9.0% return on equity will be used to modify the capital structure filed with each rate case and the return on equity will be the only modification to the capital structure used to calculate the return on the regulatory asset after the retirement date of the units. [MPSC Case No. U-21090, June 23, 2022 Order, Exhibit A, page 5.]

The Commission most recently approved the treatment described above in the Order in Case No. U-21585.

Q. Please describe Exhibit A-77 (PDD-53).

A. Exhibit A-77 (PDD-53) calculates the regulatory asset balance and amortization expense for Campbell Units 1, 2, and 3. The exhibit starts with the regulatory asset balances as of December 31, 2024 for Campbell Units 1 & 2 in column (c), line 3, and for Campbell Unit 3 in column (c), line 7. These balances are rolled forward by subtracting the amortization expense for the subsequent periods. The amortization expense is calculated in line 2 through May 2031 for Campbell Units 1 and 2. The amortization expense for Campbell Unit 3 is calculated in line 6 through May 2040. Finally, the 13-month average regulatory asset balances for the projected test year period are included on lines 4 and 8, column (f), for Cambell Units 1 & 2 and Campbell Unit 3, respectively.

Q. How are the results of these exhibits included in the instant case?

A. The average rate base amount for the projected test year ($314.6 million for Campbell Units 1 and 2, and $773.0 million for Campbell Unit 3) have been excluded from the test year projected working capital on Exhibit A-12 (PDD-34), Schedule B-4. The amortization expense ($68.6 million for Campbell Units 1 and 2, and $56.9 million for Campbell Unit 3) have been included in the projected depreciation and amortization expense on Exhibit A-13 (PDD-43), Schedule C-6.

Q. Why did the Company exclude Campbell Units 1, 2, and 3 projected regulatory asset balances from working capital, and how is the Company addressing the lower return on equity approved for the Campbell regulatory asset after the retirement date of the units?

A. As noted above, the Settlement Agreement approved by the Commission in Case No. U-21090 requires the overall return on the Campbell regulatory asset to reflect a return on

equity of 9% after retirement of the units in May 2025. To accomplish this, I have excluded the regulatory asset from the balances underlying the base rate revenue deficiency calculations. Instead, I am supporting a separate return calculation for the Campbell regulatory asset on Exhibit A-81 (PDD-57) with an ROE of 9%. The resulting return on the Campbell regulatory asset is included in the Company's overall revenue deficiency presentation on Exhibit A-11 (PDD-28), Schedule A-1, line 9.

D. Decommissioning and Ash Disposal Costs

Q. Did the Commission approve a regulatory asset treatment for the decommissioning and ash disposal costs for certain coal units?

A. Yes. First, the Settlement Agreement approved by the Commission in Case No. U-20849 established the following:

> The decommissioning costs, less salvage value, related to D.E. Karn Units 1 and 2 and the ash disposal costs related to D.E. Karn Units 1 and 2 and the Classic 7 sites (i.e. the three units at the J. R. Whiting Generating Complex near Luna Pier, two units at the B.C. Cobb Generating Plant in Muskegon, and two units at the Karn/Weadock Generating Complex near Bay City) will be recorded, as spent, to a regulatory asset. The Company may request recovery in future base rate proceedings, and upon Commission determination that those costs are reasonable and prudent, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts. [MPSC Case No. U-20849, December 9, 2021 Order, Exhibit A, pages 2-3.]

Second, the Settlement Agreement approved by the Commission in Case No. U-21090 established the following:

> [T]he Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of

> the associated decommissioning and ash disposal costs will be treated as follows:
>
> a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and
>
> b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts. [MPSC Case No. U-21090, June 23, 2022 Order, Exhibit A, page 5.]

Finally, the Settlement Agreement approved by the Commission in Case No. U-21224 provided the following:

> The Commission should approve the Company's proposed D.E. Karn Units 1 and 2 decommissioning plan and the amortization of the regulatory asset associated with the Karn Units 1 and 2 decommissioning costs and the Karn Units 1 and 2 and the Classic 7 ash disposal costs. The costs associated with Karn Units 1 and 2 decommissioning will be amortized through 2031 beginning in 2024 and the Karn Units 1 and 2 and Classic 7 ash disposal costs will be amortized over 10 years beginning in 2024. [MPSC Case No. U-21224, January 19, 2023 Order, Exhibit A, page 7.]

Most recently, the Commission approved the treatment described above in the Order in Case No. U-21585.

Q. Please describe Exhibit A-78 (PDD-54) and Exhibit A-79 (PDD-55).

A. Exhibits A-78 (PDD-54) and A-79 (PDD-55) calculate the projected test year regulatory asset balance and amortization expense for the following: (i) Karn Units 1 and 2 decommissioning costs; (ii) Campbell Units decommissioning costs, and (iii) Karn Units 1 and 2, Classic 7, and Campbell Units ash disposal costs. The total of $133.5 million average rate base amount for the projected test year has been included in the projected

working capital on Exhibit A-12 (PDD-34), Schedule B-4, and the total of $18.9 million amortization expense has been included in the projected depreciation and amortization expense on Exhibit A-13 (PDD-43), Schedule C-6.

E. Pension/OPEB Volatility Mechanism

Q. Please explain Exhibit A-80 (PDD-56).

A. Exhibit A-80 (PDD-56) calculates the projected test year regulatory asset and liability balances, and the corresponding amortization expense, related to the Pension and OPEB Volatility Mechanism approved by the Commission in Case Nos. U-21224, U-21389, and U-21585. This volatility mechanism allows the Company to defer for future recovery or refund pension and OPEB expenses above or below approved amounts. The net total of ($1.8) million average rate base amount for the projected test year has been included in the projected working capital on Exhibit A-12 (PDD-34), Schedule B-4, and the total of ($0.1) million amortization expense has been included in the projected other O&M expense on Exhibit A-13 (PDD-41), Schedule C-5.

F. SAP S/4HANA Implementation Project Recovery

Q. Please describe the SAP S4/HANA Project.

A. The SAP S4/HANA Project will modernize the Company's current Enterprise Resource Planning SAP solution that will reach the end of mainstream vendor maintenance on December 31, 2027. The completion of this project is crucial. Operating the system beyond the end of the support date creates significant risks including the inability to comply with regulatory mandates, perform core customer supporting business operations, and apply the latest security patches that are critical for cyber security protection. The project is described in more detail in the testimony of Company witness Baker.

Q. Please describe amounts included for recovery in this rate case related to the SAP S4/HANA Project.

A. The Company has included $20.4 million of bridge year and $34.8 million of test year capital spending and $15.2 million of O&M expense in the case. None of the capital spending will close to plant in service during the test year of this case. As a result, the case does not include any of the associated depreciation expense and the return on amounts included in construction work in progress have been offset by allowance for funds used during construction. In other words, there is no financial impact to the case resulting from the capital spending. The O&M expense has a dollar for dollar or $15.2 million impact on the revenue deficiency.

Q. How does the Company propose to address the O&M expense for this project?

A. The Company is proposing to defer the associated O&M expense for the project and amortize it over 15 years consistent with the life of the assets. This proposal prevents the need for customers to fund spikes in the Company's IT O&M expense during the project and instead smooths the collection over the life of the asset. The deferral will also tie the recovery to the time period over which the spending will provide benefits to the Company and its customers. This is the most appropriate method of recovering the O&M expense related to the project.

Q. If the proposed deferral is approved how will the case be impacted?

A. If the deferral is approved, the revenue deficiency of the case should be lowered by $14.6 million. As shown on Confidential Exhibit A-86 (PDD-62), this reduction includes the removal of the O&M expense and replaces it with the inclusion of the expense as a deferral in working capital.

Q. Does the implementation of this deferral require any specific accounting approvals?

A. Yes. The proposed deferral would result in a regulatory asset to be amortized over 15 years. The Company requests approval to recognize a regulatory asset to record these deferred expenses.

Q. Are there any other requests related to the SAP S4/HANA Project?

A. Yes. The Company also requests a 15-year amortization period for the cloud implementation costs for the SaaS solutions to create consistency of recovery for all aspects of the cost of the SAP S4/HANA Project. This would lengthen the amortization period from being tied to the duration of the initial license to the life of the asset. This provides customer benefit by spreading these costs over a longer period and matching the recovery to the period over which this spending will provide benefit to the Company and its customers.

G. Line Clearing Program Ramp-up

Q. What is the Company proposing with respect to its LVD Line Clearing Program expenditures in this case?

A. The Company is proposing to increase its LVD Line Clearing Program O&M expenditures significantly above historical levels toward attaining a five-year clearing cycle and more aggressive line clearing on targeted three phase primary lines. As discussed by Company witness Stewart, this "ramp-up" in LVD line clearing spending will occur over a five-year period, and at its termination in 2031 the Company expects to maintain a steady-state five-year cycle for its LVD system.

Q. What level of funding is projected for the ramp-up period to achieve the five-year cycle?

A. The total O&M projected expense requirements from 2026 through the 2030-2031 test period (the "ramp-up" period) for the entire Line Clearing Program are supported by Company witness Stewart in Figure 13 of her direct testimony. The amounts within Figure 13 represent expenditures for both the LVD and HVD system. Witness Stewart bifurcates the expenditures between "total" O&M and "baseline" O&M expenses and explains the methodology to calculate each. The difference between the "total" and "baseline" expenditures represents the incremental ("ramp-up") costs for the Company to achieve its vision for a 5-year line clearing cycle for the LVD system. The "ramp-up" costs attributable to achieving a five-year line clearing cycle for the LVD system total approximately $256 million from 2026 through the 2030-2031 test period.

Q. Is the Company seeking recovery of the incremental "ramp-up" expenditures in O&M levels in its projected period revenue requirement?

A. No. The Company is seeking approval in this case to defer the "ramp-up" related expenses as a regulatory asset once the "ramp-up" begins and through its completion (i.e., beginning in 2026 and through the 2030-2031 test period). The Company will securitize the regulatory asset when it reaches an appropriate balance. However, the Company's offer to securitize the balance is conditional upon receiving a return on the deferred expenses at the Company's prevailing weighted average cost of capital during the "ramp-up" period and until securitization takes place. This requirement and securitization of the deferred expense are supported by Company witness Bleckman.

Q. Why is it appropriate to defer and then securitize the "ramp-up" related Forestry expenses?

A. Allowing the deferral of the expenditures above the level that is included in rates approved in this case (the "baseline" O&M expense) will ensure that customers only pay for work that is accomplished. Additionally, the benefits provided by the "ramp-up" will continue for years after the work is completed. Allowing these costs to be deferred and then securitized with a five-year amortization period will better match those benefits to the recovery of the costs. Finally, the securitization of these deferred expenses will lower the cost to customers due to lower cost-of-debt-only financing.

Q. If the proposed deferral is approved how will the case be impacted?

A. If the deferral is approved, the revenue deficiency of the case should be lowered by $21.4 million. As shown on Exhibit A-82 (PDD-58), this reduction includes the removal of the test year "ramp-up" O&M expense and replaces it with the inclusion of the expense as a regulatory asset in working capital.

Q. Does the implementation of this deferral require any specific accounting approval?

A. Yes. The Company requests approval to recognize a regulatory asset to record these deferred expenses.

IV. DISTRIBUTION DEFERRAL

Q. Did the Commission approve the deferral of the revenue requirement of certain distribution capital spending for the period of March 1, 2024 to February 28, 2025?

A. Yes. In its March 1, 2024 Order in Case No. U-21389, the Commission approved deferred accounting for the return on, return of, and property taxes associated with actual capital spending from March 1, 2024 through February 28, 2025 above the following amounts

until rates were reset in a subsequent case: $158.4 million for new business, $147.6 million for reactive demand failures, and $52.5 million for asset relocations. Subsequently, in its March 21, 2025 Order in Case No. U-21585, the Commission approved to extend the deferral of the revenue requirement associated with capital spending for the aforementioned time period above rate levels until actuals are included in rates. The capital spending amounts approved in Case No. U-21585 were: $281.1 million for new business, $188.9 million for reactive demand failures, and $53.3 million for asset relocations.

Q. Are you sponsoring any exhibits related to the March 1, 2024 to February 28, 2025 distribution deferral in this case?

A. Yes. Exhibit A-84 (PDD-60) is presented in support of the distribution deferral revenue requirement.

Q. Did the Company have actual capital spending above the amounts included in the rates for new business, reactive demand failures, and asset relocation?

A. Yes. As provided on page 2 of Exhibit A-84 (PDD-60), the Company had actual capital spending for the period of March 1, 2024 to February 28, 2025 above the amounts included in rates for all three of the referenced capital spending programs.

Q. Are any of these programs included in the Investment Recovery Mechanism ("IRM") sponsored by Company witness Myers in the instant case?

A. No. The IRM proposal sponsored by Company witness Myers is designed for programs unrelated to new business, reactive demand failures, and asset relocations.

Q. Have you calculated the return on, return of, and property tax related to the capital spending above the amounts included in rates for new business, reactive demand failures, and asset relocation?

A. Yes. Exhibit A-84 (PDD-60) provides the calculation of the return on, return of, and property tax expense attributable to the capital spending for the period of March 1, 2024 through February 28, 2025 above the amounts approved in Case No. U-21389 and Case No. U-21585. The $24.3 million total amount was calculated to represent the additional revenue requirement from March 1, 2024 through April 30, 2026, that would have been built into rates if the additional capital spending would have been included.

Q. Was the Company able to record revenue for the full return associated with the capital spending above amounts included in the Settlement Agreement?

A. No. Per accounting guidance, the Company was not able to record revenue associated with the return on equity portion of the cost of capital. Revenue related to the return on equity will not be recorded until collected from customers. The regulatory asset account related to this deferral includes the return on equity but there is a contra regulatory asset account that offsets the regulatory asset by the amount related to the return on equity. The regulatory asset account houses the total revenue requirement.

Q. How does the Company propose to collect the total deferral from customers?

A. Similar to the recovery of the deferral surcharge approved in Case No. U-21585, the Company proposes that a 12-month charge be established to collect the $24.3 million total deferral. The Company further proposes that the charge be implemented for service rendered on and after the effective date of the final order in the instant case and terminating

after 12 months. Company witnesses Davis and Connolly sponsor the allocation and design of the charge, respectively.

Q. Did the Commission approve the deferral of the revenue requirement of certain distribution capital spending for the test year ending February 28, 2026?

A. Yes. In its March 21, 2025 Order in Case No. U-21585, the Commission also approved deferred accounting for the return on, return of, and property taxes associated with actual capital spending above the approved amounts for the test year ending February 28, 2026, for new business, reactive demand failures, and asset relocations until actual capital spending is included in rates. The approved amounts for these programs for the test year ending February 28, 2026, are shown in Exhibit A-85 (PDD-61).

Q. Is the Company making a proposal in the instant case regarding the distribution deferral mechanism?

A. Yes. The Company is requesting the Commission to approve the following: (i) the continuation of the deferral mechanism approved in Case No. U-21585 for the test year ending April 30, 2027; and (ii) the straight-line amortization of the associated regulatory asset balance.

V. DEMAND RESPONSE

Q. Please describe Exhibit A-83 (PDD-59).

A. Exhibit A-83 (PDD-59) is a three-page exhibit that calculates the projected test year revenue requirement for DR programs as included in this case. The first page of the exhibit summarizes the total projected test year revenue requirement for DR programs. This first page includes the results of the second and third page. The second page of the exhibit calculates the projected test year revenue requirement for the residential DR programs, and

the third page of the exhibit calculates the projected test year revenue requirement for the commercial and industrial DR program. This exhibit establishes the revenue requirement included in rates as proposed in the instant case. Should the Commission adjust the capital or O&M spending requested for DR, it would be necessary to update this exhibit to reflect those changes. Company witness Connolly is also using this exhibit in the calculation of the proposed DR Surcharge. As described by Company witness Connolly, the revenue requirement for DR is removed from the calculation of base rates and is presenting the recovery of DR revenue requirements through a surcharge, as approved in Case No. U-21585.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REVISED REBUTTAL TESTIMONY

OF

PATRICK D. DALY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Patrick D. Daly, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Patrick D. Daly who previously presented direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to:

- Respond to Attorney General ("AG") witness Sebastian Coppola's recommendations regarding the accounting treatment of the Company's SAP S4/HANA project;
- Address arguments and recommendations from AG witness Coppola and Citizens Utility Board of Michigan ("CUB") witness Richard J. Bunch concerning the Company's Low Voltage Distribution ("LVD") forestry ramp-up proposal;
- Rebut recommendations from Natural Resources Defense Council, Sierra Club, and CUB (collectively "MNSC") witness Douglas B. Jester related to the Company's LVD pole replacement investments;
- Respond to AG witness Coppola's recommendation regarding the Company's working capital cash balance; and
- Present an adjusted revenue deficiency reflecting the revised rebuttal position of Consumers Energy witnesses.

Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-208 (PDD-63)	Adjusted Revenue Deficiency for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-209 (PDD-64)	Adjusted Rate Base for the Projected 12-Month Period Ending April 30, 2027;

Exhibit A-210 (PDD-65)	Adjusted Utility Plant for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-211 (PDD-66)	Capital Spending Reconciliation for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-212 (PDD-67)	Adjusted Working Capital for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-213 (PDD-68)	Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-214 (PDD-69)	Reconciliation of Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-215 (PDD-70)	Adjusted Operations & Maintenance Expenses for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-216 (PDD-71)	Income Tax Effect of Interest for the Projected 12-Month Period Ending April 30, 2027; and
Exhibit A-217 (PDD-72)	Interest Synchronization Adjustment for the Projected 12-Month Period Ending April 30, 2027.

Q. Are there any statements you would like to make regarding your rebuttal testimony?

A. Yes. Items not specifically addressed in my rebuttal testimony should not be construed to indicate my agreement with them.

Accounting for SAP S4/HANA

Q. Please describe AG witness Coppola's recommendations regarding the SAP S4/HANA project.

A. On page 95 of his direct testimony, Mr. Coppola indicates that the project is too premature to justify including any capital expenditures in this rate case. He also recommends the Commission reject the Company's proposal to defer forecasted operating and maintenance ("O&M") costs into a regulatory asset citing his perception of a lack of firm project execution plans. Additionally, while not explicitly addressed, Mr. Coppola appears to

oppose the Company's accounting proposal to extend the amortization period for the cloud implementation costs related to the SAP S4/HANA Software as a Solution ("SaaS") solutions to 15 years.

Q. Does the Company agree that SAP S4/HANA costs should not be included in this case?

A. No. Company witness Stacy H. Baker continues to support the inclusion of the SAP S4/HANA project, as outlined in her rebuttal testimony.

Q. Do you agree with Mr. Coppola that the accounting requests related to the SAP S4/HANA project should be denied?

A. No. As explained in my direct testimony, approving the deferral of O&M expenses will allow the Company to align cost recovery with the period over which the project delivers benefits. The same rationale applies to the request to amortize cloud implementation costs over 15 years. These proposals help mitigate customer rate impact by smoothing expenses over the life of the project. Mr. Coppola offers no specific critique of these accounting requests beyond asserting that the project is too preliminary for inclusion in this case.

Q. Has the Commission previously approved the Company's requested accounting treatment for SAP S4/HANA investments?

A. Yes. In the Commission's September 30, 2025 Order in Consumers Energy's gas rate case, Case No. U-21806, the Commission agreed with Consumers and found "*the company's request to defer investment O&M expense over the 15-year life of the project and to amortize cloud computing costs associated with the project over the same 15-year period will lessen impacts to customer rates*" (page 226). This supports the Company's proposed accounting treatment, and I recommend the Commission reject Mr. Coppola's proposal.

LVD Forestry Ramp Up

Q. Please describe the Company's proposal with respect to its LVD Line Clearing Program expenditures in this case.

A. As outlined in my direct testimony, the Company is proposing to increase its LVD Line Clearing Program O&M expenditures significantly above historical levels to obtain a five-year clearing cycle and more aggressive line clearing on targeted three-phase primary lines. Additionally, the Company requested approval to defer "ramp-up" or "incremental expenditures" above a defined "baseline" expense as a regulatory asset once the ramp-up begins and through its completion (i.e. beginning in 2026 and through the 2030-2031 test period). As explained in my direct testimony, the benefit of this proposal is to better match the benefits provided by the "ramp-up" to the recovery of costs and to mitigate rate impact to customers.

Q. Did the MPSC Staff ("Staff") or other intervenors oppose the Company's proposed "ramp-up" spending levels or the request to defer such costs to a regulatory asset?

A. No. In fact, there is broad support for the Company's total proposed LVD O&M expenses and the proposal to defer "ramp-up" costs to a regulatory asset. The following excerpts from the parties' testimony illustrate this support:

- AG witness Coppola, "*agree[s] in principle with the proposal to defer the line or tree clearing costs above a reasonable threshold*" (page 174, lines 14 to 15).
- CUB witness Bunch testified, "*I support the Company's operational plan and spending level, which I consider to be consistent with the recommendations of the Liberty Audit. I also agree that the line clearing surge costs should be held as regulatory assets*" (page 39, lines 12 to 14).
- Staff witness Duell indicated, "*Staff supports the requested $186,684,000 for the projected test year O&M expense. It is crucial to allow Consumers to spend the full amount for line clearing to increase the resiliency of Consumers Energy's electric distribution system"* (page 7, lines 23 to 25) and

"*Staff supports the Company's proposal to recover LVD line clearing O&M spending in the test period as a regulatory asset*" (page 8, lines 16 to 17).

Given the absence of opposition and broad support from intervenors, I recommend the Commission approve the Company's proposal to defer ramp-up forestry costs as a regulatory asset.

Q. Is there any opposition to the Company's proposed cost recovery mechanism for the resulting forestry "ramp-up" regulatory asset?

A. Yes. As explained in my direct testimony, the Company proposed securitizing the regulatory asset once it reaches an appropriate balance. This was conditional upon receiving a return on the regulatory asset at the Company's prevailing weighted average cost of capital ("WACC") during the "ramp-up" period and until securitization takes place. However, both Staff witness Duell and AG witness Coppola opposed this approach, contending that the Company should only earn a return at its short-term debt rate. Company witness Marc R. Bleckman addresses these concerns in his rebuttal testimony, reaffirming support for the Company's original cost recovery proposal and defending the use of WACC as a fair and reasonable return.

Q. Please describe any other opposition raised with respect to the Company's forestry "ramp-up" proposal.

A. Baseline expenses represent the amount of funding that is included in rates for the test year. Under the Company's proposal, any expenses incurred above the defined baseline would be deferred to the regulatory asset. On page 174 on his direct testimony, AG witness Coppola asserts that the Company has calculated "baseline" O&M expenses that are too high, which results in a reduced opportunity to defer and securitize a higher amount of tree clearing costs. CUB witness Bunch makes a similar assertion on pages 39 through 40 of

his direct testimony, arguing the Company's approach to calculate the "baseline" O&M expense is speculative.

Q. How did AG witness Coppola and CUB witness Bunch develop their proposed LVD Line Clearing O&M baseline?

A. On page 175 of his direct testimony, Mr. Coppola indicates that the historical period (2024) forestry expenses represents a reasonable baseline of tree clearing expenses for the projected test year "baseline." Mr. Bunch also utilizes 2024 historical spend but adjusts the baseline figure for inflation factors to arrive at the projected test year amount as described on page 40 of his direct testimony.

Q. Do you agree with this approach?

A. I do not. The approach taken by AG witness Coppola and CUB witness Bunch is overly simplistic and fails to reflect the operational and strategic planning embedded in the Company's acceleration to a five-year LVD line clearing cycle as supported by Company witness Sara E. Stewart's direct and rebuttal testimony. Mr. Coppola and Mr. Bunch's reliance on 2024 historical spending, either directly or with minimal inflation adjustments, ignores the Company's demonstration that the cost of achieving the ramp-up (and the resulting future "steady-state maintenance" of the cycle) is significantly higher than maintaining historical levels of expense in which the Company was on a seven-year effective cycle. Their approach disregards changes that are appropriately considered in a projected test year. The use of a projected test year is intended to account for such forward-looking changes.

Company witness Stewart provided detailed direct testimony outlining the fundamental shift in operations required to transition to a five-year LVD line clearing

cycle. Her testimony also supported the estimated annual expense to maintain the LVD system on a five-year cycle in a steady state once the cycle is achieved in 2031. The expense assumptions within her testimony and supporting exhibits were built on factors such as overall crew resourcing, the elimination of all back-log miles, the consideration of overtime for both local and out-of-state tree crews, among other items. The projected test year "baseline" expense was derived from this forward-looking analysis and brought back to test period dollars. Notably, no intervenor disputed the Company's total LVD Line Clearing O&M request for the projected test period, which was built utilizing these assumptions.

The methodology proposed by Mr. Coppola and Mr. Bunch appears designed to suppress the test year "baseline," thereby limiting the Company's ability to recover a substantial portion of O&M costs within the LVD expense included in base rates. Company witness Bleckman's rebuttal testimony describes the negative credit implications of adopting a lower baseline. Coupled with Mr. Coppola's proposal to allow only a short-term debt rate on the regulatory asset, this punitive approach undermines the reliability goals of the program which have broad support in this case and are consistent with the Liberty Consulting Group ("Liberty") Audit recommendations adopted by the Commission. Additionally, the methodology used to establish the baseline should be weighed against the Company's deliberate effort to balance reliability improvements with customer affordability. Once again, by deferring and securitizing these costs, the Company is mitigating immediate customer rate impacts.

For these reasons, the baseline methodology proposed by Mr. Coppola and Mr. Bunch lacks merit. I continue to support Company witness Stewart's approach to

calculating the LVD baseline expense for the test year as reasonable, well-supported by the evidence in this case, and aligned with long-term reliability objectives. I recommend that the Commission adopt the Company's methodology for calculating the LVD baseline line clearing expenses and reject the alternative proposals offered by Mr. Coppola and Mr. Bunch.

Q. Do you have any final observations related to Mr. Coppola and Mr. Bunch's recommendation for the proposed baseline level of forestry expense?

A. Yes. As discussed above, Mr. Coppola uses the Company's actual 2024 forestry spend of $110.2 million as the basis for his proposed baseline. On page 40 of his direct testimony, Mr. Bunch applies an inflation adjustment to the Company's 2024 actual forestry expense to yield a baseline of approximately $114 million.

Company witness Stewart's direct testimony, specifically Figure 20, outlines authorized and actual forestry spending across the Company's five most recent rate cases. This data shows a consistent upward trend, reflecting the Company's commitment to achieving a shorter forestry cycle. In the Company's most recent rate case, Case No. U-21585, the Commission authorized the Company to spend approximately $125 million in forestry. This currently authorized amount is in excess of Mr. Coppola and Mr. Bunch's proposed baseline amounts. The continued upward trend in both actual and authorized spending supports the reasonableness of the Company's proposed baseline. It would be unreasonable to set the baseline level of forestry expense below currently authorized spending levels, particularly as the Company transitions to a more aggressive five-year forestry cycle that requires increased investment. Therefore, Mr. Coppola and Mr. Bunch's proposed baseline levels are too low and should be rejected by the Commission.

LVD Pole Replacement Surge Proposal

Q. What does MNSC witness Jester recommend with respect to LVD pole replacements?

A. On page 16 of his direct testimony, Mr. Jester recommends the Commission order the Company to defer and propose securitization of its projected spending for a surge in LVD pole replacements. Mr. Jester proposes a baseline spending amount for LVD pole replacements of $25 million and recommends that all pole replacement costs exceeding this amount be considered as surge expenditures.

Q. How do you respond?

A. I disagree with Mr. Jester's proposal. First, the Company objects to the use of securitizations for these investments in its distribution system. Historically, utility securitizations have been reserved for the recovery of stranded costs associated with assets that no longer provide a benefit to customers and/or material non-recurring expenses. The decision to propose securitization for the forestry ramp up expenditures was made to mitigate the rate impacts from the increase in this operating expense. It was also intended to spread the cost to customers more evenly over the time horizon of the anticipated benefits.

Unlike line clearing, which is a recurring operational expense, capital investments such as LVD pole replacements result in long-lived assets that provide long-term benefit to customers and merit inclusion in the Company's permanent capital structure. These expenditures should be recovered through traditional rate base treatment, allowing for depreciation over time and proper cost allocation across the customers who benefit. For these reasons, I recommend the Commission reject Mr. Jester's proposal.

Working Capital Cash Balance

Q. Please describe AG witness Coppola's recommendations regarding the Company's cash balance included in working capital.

A. On pages 102 through 103 of his direct testimony, Mr. Coppola recommends that the Company's projected test year cash balance included in working capital of $50.4 million be reduced by $41.4 million to $9.0 million. He arrives at this figure by first calculating a three-year average cash balance of $25.1 million, then removing $16.1 million of cash held in interest-bearing accounts, which he argues should not be included in working capital. Mr. Coppola asserts that his calculation of a $9.0 million cash balance more accurately reflects the Company's operational cash needs.

Q. How do you respond?

A. I do not agree with Mr. Coppola's proposed methodology. Company witness Bleckman refutes the AG's position with respect to the Company's projected cash balance of $50.4 million. Furthermore, even if the Commission were to reject the Company's methodology to calculate its projected working capital cash balance, it should not adopt Mr. Coppola's flawed proposal.

First, it is inappropriate to exclude cash held in interest-bearing accounts from the working capital calculation. These funds are maintained in unrestricted operating accounts and are readily available to meet the Company's short-term liquidity and operational needs. Moreover, the interest income generated from these accounts is included as a direct offset to the revenue requirement. This treatment is reflected in the projected Net Operating Income shown on Exhibit A-13 (PDD-37), line 6.

Second, even if the Commission rejected the Company's proposed approach as described by Company witness Bleckman, which it should not, then the appropriate cash balance should be the historical 13-month average of $36.4 million as shown on Exhibit A-12 (PDD-34), line 1 (column d), not a three-year average balance as proposed by Mr. Coppola. It is the long-standing practice of the Company, and one accepted by the Commission, to calculate working capital utilizing a 13-month average of historical balances. Mr. Coppola's methodology results in an understatement of the Company's actual working capital cash needs.

I recommend the Commission reject Mr. Coppola's arguments and adopt the Company's as-filed capital cash balance of $50.4 million as supported by Company witness Bleckman.

Adjusted Revenue Deficiency

Q. Please describe Exhibits A-208 (PDD-63) through A-217 (PDD-72).

A. Exhibits A-208 (PDD-63) through A-217 (PDD-72) present the calculation of the Company's adjusted revenue deficiency for the projected 12-month period ending April 30, 2027. As shown on Exhibit A-208 (PDD-63), line 10, column (e), the Company has recalculated a test year revenue deficiency of $~~407.7~~ 422.9 million, a reduction of $~~28.2~~ 13.0 million from the Company's original filing in this case.

Q. Why is the Company proposing an adjusted test year revenue deficiency?

A. Based on certain facts and circumstances revealed subsequent to filing the case, the Company believes it is appropriate and necessary to make certain adjustments.

Q. Please summarize the proposed adjustments to the revenue deficiency.

A. The Company has made the following adjustments to its originally filed revenue deficiency:

1. Total decrease to net utility plant of $37.2 million, depreciation expense of $1.3 million, and property taxes of $0.5 million. A list of the individual adjustments, with descriptions and sources, is provided in Exhibit A-210 (PDD-65) and Exhibit A-211 (PDD-66);

2. Total decrease of $0.7 million to other O&M. A list of the individual adjustments, with descriptions and sources, is provided in Exhibit A-215 (PDD-70); and

3. A decrease in the Company's calculation of overall cost of capital from 6.35% to 6.30% as described in the rebuttal testimony of Company witness Bleckman.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Thank you, Your Honor.

Next we have company witness Alex M. Gast. Who had direct testimony consisting of a cover page and 20 pages of questions and answers. Mr. Gast also had rebuttal testimony consisting of a cover page and three pages of questions and answers aside from Exhibit A-12 that has other witnesses sponsoring parts of it, Mr. Gast sponsored Exhibit A-95 and Exhibit A-182.

THE COURT: Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct and rebuttal testimony of Alex Gast is bound into the record and Exhibits A-95 and A-182 are admitted.

(At 2:55 p.m., exhibits A-95 and A-182 are admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

ALEX M. GAST

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Alex M. Gast, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. What is your position with Consumers Energy Company ("Consumers Energy" or the "Company")?

A. I am the Manager of Customer Regulatory Strategy in the Customer Experience department.

Q. Please state your educational background and work experience.

A. In 2011, I graduated from Central Michigan University with a Bachelor of Science degree in Business Administration, with a major in accounting. In 2013, I graduated from Spring Arbor University with a Master of Arts degree in Business Administration. I am also a Certified Public Accountant registered in the state of Michigan.

From 2012 to 2014, I was employed by Plante & Moran as a Staff Auditor. My responsibilities included the planning and execution of financial statement audits, reviews, and consulting engagements for a variety of non-profit, healthcare, and manufacturing clients.

In 2014, I joined Consumers Energy as a Business Support Advisor in the Distribution, Operations, Engineering, and Transmission department. My responsibilities included managing financial budgets, forecasts, and long-term financial plans for natural gas and electric programs. In 2015, I joined the Energy Resources department as a Financial Analyst where I worked on business plans and performance metrics and was promoted to the lead of that team in 2016. In 2018, I joined the Pricing section of the Rates and Regulation department, and my responsibilities included cost of service studies, rate

design, research and development of additional services, analyses for Senior Management, and customer-specific rate analyses. In 2023, I joined the Customer Experience department as a Principal Rate Analyst and was promoted to Manager of Customer Regulatory Strategy in 2025. I am responsible for regulatory strategy and filings related to the Company's clean energy plan, including Demand Response ("DR") and Energy Waste Reduction ("EWR").

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I filed testimony on behalf of the Company in the following proceedings before the Commission:

Case No. U-20365	2018 EWR Reconciliation;
Case No. U-20372	2020-2023 EWR Plan;
Case No. U-20650	General Gas Rate Case;
Case No. U-20702	2019 EWR Reconciliation;
Case No. U-20865	2020 EWR Reconciliation;
Case No. U-20875	2022-2025 EWR Plan;
Case No. U-20893	Investment Recovery Mechanism Reconciliation;
Case No. U-21148	General Gas Rate Case;
Case No. U-21389	General Electric Rate Case;
Case No. U-21647	2023 DR Reconciliation; and
Case No. U-21906	2024 DR Reconciliation.

Q. What is the purpose of your direct testimony in this case?

A. The purpose of my direct testimony is to describe the Company's DR program, associated costs, and proposed updates. As part of my direct testimony, I will address: (i) the DR

operating and maintenance ("O&M") expenses and capital investments in the test year ending April 2027.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (AMG-1)	Schedule B-5.5	Actual and Projected Capital Expenditures – Demand Response;
Exhibit A-95 (AMG-2)		Summary of Actual & Projected O&M Expenses – Demand Response; and
Exhibit A-182 (AMG-3)		Whole Home Optimization Demand Response pilot.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please describe the exhibits you are sponsoring.

A. Exhibit A-12 (AMG-1), Schedule B-5.5, details the capital expenditures related to DR in the historical year, bridge period, and projected in the test year. Exhibit A-95 (AMG-2), page 1, details the O&M expenses related to DR in the historical year and projected in the test year. Exhibit A-95 (AMG-2), page 2, includes projections for DR O&M based on inflation. This page is not intended to represent how the Company has developed its projected DR O&M. Column (b) shows the historical O&M expense. Column (c) shows the historical amount to which an inflation rate or merit increase rate was applied. Columns (e) and (g) show the amounts to which a hypothetical inflation rate or merit increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the hypothetical merit and inflation increases for each respective period. Because the Company does not develop the projected DR O&M using inflation it is necessary to include column (i), other adjustments. Column (i) is simply the difference between the Company's

actual projected O&M and what the O&M would have been if the Company had used inflation to project DR O&M. Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i). The expenses supported here are based upon the expenses necessary to meet the needs of DR program planned in the test year and are not based on applying an inflation rate to the historical O&M expenses.

Q. Please explain the DR programs offered by the Company.

A. The Company offers a DR portfolio comprising of both residential and business DR programs. The portfolio consists of three residential programs: Device Cycling, Dynamic Peak Pricing ("DPP"), Residential Smart Thermostat; and two business programs: Commercial and Industrial ("C&I") Contractual DR, and C&I Rate options.

- Residential Device Cycling involves installing direct load control switches on high energy use equipment at customer homes. These switches are capable of receiving DR event signals that turn off connected loads for a specified amount of time during events. At the end of 2024, the program had over 95,000 participants and represents 57.3 MW of enrolled capacity.

- Residential DPP offers customers pricing options that are designed to incentivize reduced energy use during peak hours. At the end of 2024, the program had over 176,000 participants and represents 37.9 MW of enrolled capacity.

- The Residential Smart Thermostat Program uses cloud-based software deployed through the customer's Wi-Fi thermostat to optimize energy savings. As of 2024, the program had nearly 59,000 participants and represents 54.2 MW of enrolled capacity.

- The Business DR Contractual Program offers payment based on contractual agreement to reduce load by a contract amount during Midcontinent Independent System Operator, Inc. ("MISO") emergencies during all MISO seasons. The Business DR Contractual Program has set event, duration, and timeframe limits specified in the agreement. As of 2024, the program included 1,402 accounts and 249 MW of enrolled capacity.

- Business DR Rate Options includes the General Interruptible ("GI") and General Interruptible 2 ("GI2") rate provisions, Rate Energy Intensive Primary ("EIP"), and Long-Term Industrial Load Retention Rate ("LTILRR") which provide discounts, monthly on-bill incentives, market pricing signals, or a

combination of these to C&I customers for reducing load during emergencies year-round. Each option does include specific criteria for entry. As of 2024, Business DR Rate programs had an approximate enrollment of 39 accounts and 259.5 MWs of enrolled capacity.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. COST DETAILS

II. SURCHARGE & REGULATORY FRAMEWORK

III. RESIDENTIAL DR

IV. BUSINESS DR

V. NEW DR PILOT

VI. SUMMARY

I. COST DETAILS

Q. Please explain the O&M costs associated with the DR programs offered by the Company.

A. Projected O&M costs for the test year for these programs are $34.6 million and are included on Exhibit A-95 (AMG-2), page 1. Capital costs for these programs are projected to be $1.56 million in the test year and are included in Exhibit A-12 (AMG-1), Schedule B-5.5. These programs are designed as a lower-cost, flexible capacity resource that can be used during times of peak electricity demand to mitigate system constraints and, ultimately, to reduce costs paid by customers. This capital and O&M spending are related to enrolling (or "activating") customers interested in participating in DR and implementing DR programs.

Costs related to the DR Program are broken into three major categories – labor, contractor costs, and non-labor other.

- *Labor* spending related to DR programs is associated with internal labor resources that support the program through event operations, program management, marketing, data visualization & analytics, customer research, evaluation, and contractor support. These activities are critical in the deployment of voluntary DR programs as they require a different value proposition and resourcing than traditional electric utility service to bring to market and promote customer participation.

- *Contractor costs* are allocated to the three major contractors that Consumers Energy works with in the management of these DR programs – EnergyHub, Honeywell, and Enel X. These costs cover activities such as: managing thermostats for the Smart Thermostat Program, C&I customer portals used to dispatch event notification, incentives, installation fees for switches, thermostats, and the functional marketing costs related to digital, social, mailings, etc. Most of these contractor costs closely align with the number of customer enrollments and as enrollments continue to increase in conjunction with the Company's integrated resource plan ("IRP") plan, the Company will continue to see increased costs in these spaces related to incentives as it seeks to enroll new and retain existing customers in the face of audience saturation and looming requirements from MISO's DR reform. The Company also anticipates higher contractor Software as a Service ("SAAS") fees to manage these devices with the latest software upgrades. The Company's contracts with these contractors have financial and performance metrics included to ensure that Consumers Energy is achieving cost effectiveness.

- *Non-labor costs* are additional costs incidental to the program but not directly related to labor costs, for C&I programs most customer incentives are included in non-labor costs. When looking at capital costs for DR programs, the major contributor to cost is materials. For the residential program, the Company works with contractors for the installation of device cycling switches. For the majority of Business DR customer communications, equipment is installed to allow for dispatch communications during events and provide customers with the necessary tools to perform during events. The remaining customers receive communications that are manually triggered by CE employees.

Q. What benefit does the Company's DR Program provide?

A. Electric demand varies by season and the Company must secure sufficient capacity resources for any time of peak demand (plus a reserve margin). As a result, some generation resources are rarely fully utilized outside of high-demand summer months. DR programs help manage capacity need for peak demand, in lieu of additional supply-side electric generation or capacity contracts. Ultimately, the Company's DR programs help balance

Michigan's electricity needs to help protect the grid, react to emergencies and severe weather, and avoid the cost of additional generation infrastructure to serve peaks. Further, as discussed by Company witness Megan L. Metz, customers will receive $62 million worth of capacity value in Planning Year 2025/2026 from the MWs, or the Zonal Resource Credits, that the DR programs provide.

DR also provides the opportunity for customers to take better control of their energy usage, decrease their energy costs, and participate in the Company's Clean Energy Plan. Residential customers benefit from participating in DR programs by saving money when they shift flexible demand to hours when energy is less expensive. All customers benefit from DR reducing grid strain during peak demand periods because reducing grid strain offsets the Company's need to invest in more generation or capacity resources.

Most importantly, demand-side resources such as DR are essential to meeting climate goals and achieving the MWs approved in the IRP. The DR Program remains essential to the Company's long-term ability to achieve greater flexibility and improved sustainability over the long term.

Q. What is the Company's overall approach to DR in the future?

A. The Company has taken efforts to reduce costs and increase MWs while working to develop strategies in response to the evolving nature of DR in Michigan. The Company is focusing on programs with the greatest cost effectiveness, such as C&I programs and the Smart Thermostat Program. In addition, the Company seeks to innovate in DR and a new pilot proposal is discussed below, the pilot takes advantage of new technologies and is expected to yield useful information as the Company seeks to expand DR opportunities in the most cost-effective ways.

II. SURCHARGE & RECONCILIATION PROCESS

Q. Is the Company requesting approval of a DR surcharge in this case?

A. Yes. Consistent with the Order in Case No. U-21585, the Company has calculated a separate revenue requirement for the DR Program inclusive of all DR related capital, O&M costs, and rate credits. The DR revenue requirement is supported by Company witness Patrick D. Daly in Exhibit A-83 (PDD-59). These costs, along with the DR related credits in the Company's rate design, are included in the proposed DR surcharge supported by Company witness Laura M. Connolly in Exhibit A-16 (LMC-2), Schedule F-2.1. The DR surcharge will be adjusted during the Company's annual DR Reconciliation proceedings to account for changing costs, over/under-recoveries, and recovery of the performance incentive. During the annual reconciliation, the Company will use the same DR surcharge methodology approved by the Commission in the last approved rate case, Case No. U-21585.

Q. How will the surcharge be calculated and implemented?

A. The Company's DR reconciliation surcharge calculation methodology is supported by Company witness Connolly. The Company used the calculation methodology in the ongoing DR reconciliation proceeding, Case No. U-21906, to request surcharges to refund any overcollections, collect any under-recoveries, and for recovery of DR performance incentives. Company witness Emily A. Davis is supporting the allocation of the revenue requirement by rate class.

Q. Is the Company requesting any other changes?

A. Yes. The Company proposes that DR capital and O&M spend be considered as a part of the annual DR plan and reconciliation instead of as a part of any general rate case. The

Company proposes that, each annual DR reconciliation filing operate as both a DR plan and a DR reconciliation.

The Company has presented DR capital and O&M spend in this case as it has traditionally done, if this proposal to change the DR regulatory construct is not approved. In the annual reconciliation, the Company proposes to reconcile DR spend and incentive, while also requesting approval for spending in the subsequent year. This modification aims to further mitigate regulatory lag and reduce the complexity associated with DR in multiple cases, as illustrated by Table 1 below.

Table 1

Plan & Reconciliation Structure			Electric Rate Case Approving DR Spend			
DR Program Calendar Year	Year Reconciled	Year Surcharge Implemented	U-21389 (2023)	U-21585 (2024)	U-21870 (2025)	2026 Case
2025	2024	2026	Jan-Mar	Apr-Dec		
2026	2025	2027		Jan-Apr	May-Dec	
2027	2026	2028			Jan-Apr	May-Dec

Q. Has the Company proposed this change in other filings?

A. Yes. The Company has also proposed this change in its 2024 DR reconciliation, Case No. U-21906.

Q. When does the Company propose the new structure take effect?

A. The Company requests that the change take place with the 2025 DR reconciliation, which would be filed in 2026 to reconcile 2025 spending and propose new spending for 2027.

Q. Has DR capital and O&M been included in the present case?

A. Yes. The Company has presented DR capital and O&M spend here as it has traditionally done and has included DR O&M and Capital spend for the test year which includes a portion of 2026 and 2027.

Consequently, the requested change, prorated with what was already approved for a portion of 2026 in the Company's previous electric rate case (Case No. U-21585), would make up the 2026 ask that, if approved, would allow the Company to remove DR from the rate case, except for credits that will remain included in the rate design (reference Table 1).

III. RESIDENTIAL DR

Q. Please explain the structure of the Residential DR Program.

A. The Company offers three Commission-approved Residential DR programs: a Device Cycling program, a DPP program, and a Smart Thermostat program.

Q. Is the Company proposing any changes to the Residential DR portfolio?

A. Yes, the Company is proposing changes to the DPP program as discussed below. The Company is not proposing changes to the Device Cycling program credit that was recently updated to $5 per customer-month in June through August because of the Order in Case No. U-21585. The latest value of MISO's Cost of New Entry ("CONE") is $130,930/MW-

year in Zone 7, which is only 3% higher than the prior year and results in no change to the Device Cycling credit calculation approved in the previous rate case.

Q. Please describe the residential Device Cycling Program and the related customer benefits.

A. In the Device Cycling Program, the Company installs direct load control switches on air conditioning ("AC") units. The program ended in 2024 with 57.335 MW of capacity – the largest contributor to the residential portfolio. When the Company activates a switch, it will cycle the output of the connected load by between 40% and 75%. At the end of an event, each system returns to normal operation. In exchange, customers receive a monthly bill credit of $5 during the billing months of June through August, as recently approved in the Company's prior electric rate case, Case No. U-21585. Customers previously received a $25 enrollment incentive, but the Company discontinued this when the program was moved into maintenance mode. In months with events, customers reduce load during peak hours which can translate into a shift in kWh from the peak to off-peak period, lowering bills.

Q. Please describe the residential Smart Thermostat Program.

A. The Smart Thermostat Program is for customers who have central AC, and a participating Wi-Fi-enabled smart thermostat and agree to participate in DR events. During a DR event, customers can expect their thermostat setpoint to adjust up to 4 degrees above their current setpoint to reduce strain on the electric grid during high demand days, in the summer months of June - August. The program uses cloud-based software deployed through the customer's Wi-Fi thermostat to perform a pre-emptive energy optimization (pre-cooling) of the home to achieve greater demand savings during the duration of the DR event.

Q. Please describe the direct benefits customers receive for participating in the Smart Thermostat Program.

A. Customers participating in the Smart Thermostat Program receive an incentive for signing up in the program. If the customer already has a participating (Google Nest, Ecobee, Honeywell, Emerson, Alarm.com, or Amazon smart thermostat) device, the customer will sign up through the Bring Your Own Device ("BYOD") path and receive a Pre-Paid Mastercard as an enrollment incentive. If the customer does not already have a participating Smart Thermostat, they can purchase a thermostat through the Consumers Energy Residential Online Store and receive an instant incentive credit toward the purchase of the new DR Pre-Enrolled ("DRPE") Smart Thermostat. Both paths currently receive an annual Pre-Paid Mastercard at the end of event season for participation in the program.

Q. Please describe the Company's plans to expand the Smart Thermostat Program.

A. The Smart Thermostat Program has expanded from 1,939 participating customers in 2019 to over 58,000 cumulative customers in 2024. This plan accounts for almost 68,500 customers in the Smart Thermostat Program by the end of 2025 totaling over 63 MWs. The Company added two new thermostat options (Alarm.com and Amazon smart thermostat) in 2024 for the BYOD flow. This will continue to foster a seamless customer enrollment path and a DR solution for all Consumers Energy customers. Also, for the Smart Thermostat Program, the Company will roll out an offline device management effort in 2025. This initiative will help the Company more easily identify when a thermostat is not connected to Wi-Fi and controllable for at least 90 days or more. The Company will work with EnergyHub to send a series of emails to the offline device participants, as an effort to get the device reconnected and controllable again. After a series of email attempts to

reconnect, the Company will de-enroll participants that took no action to reconnect. This effort supports the Company's cost-effectiveness goals and could increase the program's overall kW/device savings during called DR events and thereby allowing the Company to register a higher percentage of enrolled MW with MISO as a Load Modifying Resource, providing capacity value.

Q. Please describe the residential DPP Program.

A. The Company's DPP Program is designed to encourage customers to shift their energy consumption away from the hours of a DR event. Currently, the Company offers two pricing options under the program, Critical Peak Pricing ("CPP") and Peak Time Rewards ("PTR"). The goals of the two pricing options are identical, but the approach to achieve them differs. The CPP option charges customers a significantly higher rate of $1/kWh of energy used during DR event hours. In exchange, customers are offered a discount on their rate during weekends, holidays, and all hours of the weekdays except 2 p.m. to 7 p.m. The CPP Program is generally referred to as a "stick" incentive - using strong pricing signals to reduce consumption during an event. Alternatively, the PTR option offers customers a payment for reducing their energy during DR events. This is currently a credit of $1/kWh of energy reduced during event hours as compared to their baseline use.

Q. Is the Company proposing any changes to the DPP program for the test year?

A. Yes. The Company is proposing to reduce the per customer demand savings for PTR from 0.21 kW/customer to 0.13 kW/customer and for CPP from 0.25 kW/customer to 0.18 kW/customer. The Company is also proposing to reduce the PTR credit, currently at $1/kWh of energy reduced during event hours to $0.50/kWh.

Q. Why is the Company proposing to make changes to the DPP program demand savings values and the PTR credit?

A. The Company, working with its third-party evaluator Cadmus, predicted a lower capability than the 2022 planning value previously being used. With this lower value being nearly half the previous value for PTR, the Company determined that the credit offered to these customers should also be halved.

Q. Please describe the importance of PTR as a part of DPP and the Residential DR Portfolio.

A. The PTR Program is a critical component to the Company's overall residential DR portfolio because it provides customers a no-risk option to participate in DR. From a portfolio standpoint, the Company has seen a higher enrollment rate for PTR compared to other DR offerings with 153,147 cumulative enrollments in 2024. DPP also has the highest rate of Low-Income enrollments. Although the enrollment rate for PTR is higher, the per customer demand savings are significantly lower than the rest of the portfolio (at 0.21 kW/customer, currently, and proposing to reduce further to 0.13 kW/customer) vs 0.92 kW per customer for the Smart Thermostat Program. The combination of a high conversion rate paired with low demand savings has influenced the Company's strategy to view PTR as an "entry-level" or "gateway" offering. Meaning, the Company plans to leverage the willingness of customers to participate in PTR to get them familiar with DR in a no-risk way before encouraging them to participate in a different program (primarily the Smart Thermostat Program) where demand savings to the customer and the Company are more predictable and controllable. Given the change in strategy to use PTR as a gateway DR program, the Company has made significant changes to reduce expenses for

the program to improve cost-effectiveness. The Company is: (1) working on the discontinuation of customer enrollment incentives, and (2) focusing primarily on low to no cost marketing channels including the Consumers Energy website during the time of move-in.

While PTR is not actively registered in-market, the Company continues to promote enrollments in the program that is best suited for each customer. The Company worked with over 2,328 customers to upsell them from PTR to the Smart Thermostat Program during 2024. The focus of this upsell is to promote customers to join a more cost-effective DR program while earning a higher incentive.

IV. BUSINESS DR

Q. Please explain the structure of the Business Contractual DR Program.

A. Each business customer that signs up for the Business DR Contractual Program is contracted for a specified load (kW) reduction. The Company works with individual business customers to set up a demand reduction plan at their facility that will be implemented when a DR event is called. Business customers of different sizes participate through this process to create a business DR portfolio. When MISO expects the grid to be strained because of high electric demand or during periods of high market costs, the Company notifies participants within the Business DR Program of the need to reduce load. Customers then have 30 minutes to execute their curtailment plan (unless the event is scheduled at a specific future time). The resulting reduction in peak load is for the purpose of relieving stress on the electric system in a more cost-effective manner than purchasing capacity from the market or building additional generation resources.

Q. How does the Business DR Contractual Program differ from the Company's interruptible rates?

A. The Company's interruptible rate defines specific capacity and energy billing parameters, whereas the Company's Business DR Program provides a contract with customers to defining specific program parameters. With the interruptible rate options customers are charged a lower rate in exchange for a firm commitment to reduce demand by or to a specified amount during MISO events. Participants who choose to deviate from this commitment during MISO events are assessed a significant financial penalty or are subject to higher real time market prices depending on rate or provision.

The Business DR Contractual Program also comprises demand curtailment commitments. But unlike the Company's interruptible rate options, customers choose to nominate an amount of demand they are willing to reduce during events at specific timeframes and dates for the program year. The contractual program has limits on the number of events, duration of events, and days in which events can be called. Customers receive payments for their performance during MISO Emergency Events for up to 250% of their nominated amount. The financial benefit to participating business customers is less significant with the Business DR Contractual Program than with the interruptible rate options, to recognize the reduced event risk timeframes and durations customers are exposed to.

Q. How are participants compensated for reducing their electric load during peak demand events?

A. Participants are compensated for capacity and energy reductions during events. The capacity payment is tied to kW of reduction nominated, and the energy payment is based

on kWh reduction during events. Both are measured from an established baseline in accordance with MISO calculations. Compensation for capacity is based on the customer's contracted capacity reduction during the program enrollment period. The customer receives payment for energy based on performance during events. Incentive payments are priced for market competitiveness and are a component of the overall cost of having and managing a DR capacity resource. Average nomination in Business DR is 178.8 kW and historical average capacity incentive equates to $4,774. These results will vary based on a customer's actual performance for given events.

Q. Do non-participating customers benefit from the Company offering a Business DR program?

A. Yes. The Company's Business DR Program provides a flexible, repeatable, and scalable capacity resource. The program benefits all Consumers Energy customers by reducing the need to purchase additional capacity during times of peak demand, thereby reducing the cost of providing power to all customers.

Q. Will these DR contracts be bid into MISO?

A. Yes. The Company will bid into MISO based on the portfolio capacity of participating customers. Each participating customer will be required to enter a contract with the Company, which outlines the terms of performance in keeping with MISO requirements for a Load Modifying Resource and payments as it relates to the contracted capacity and energy. Capacity payments are standardized at the same rate for all participating customers.

Q. Is the Company proposing other tariff-related changes for Business DR?

A. No. The Company is not proposing changes to the GI provision credits that were recently updated to $8.50/kW-month in summer months and $7.70/kW-month in non-summer months as a result of the Order in Case No. U-21585. The latest value of MISO's CONE is $130,930/MW-year in Zone 7, which is only 3% higher than the prior year and results in no change to the GI credit calculation approved in the previous rate case.

Q. Is the Company enhancing existing elements of the Business DR Contractual Program or developing new offerings?

A. Yes, the Company has transitioned the Business DR Contractual Program to a seasonal structure and will launch its first year-round season on June 1, 2025. Early results from this new approach have been encouraging, with seasonal contracts demonstrating improved participation and customer engagement. The Company anticipates continued growth in registered megawatts each season as it refines and optimizes the program. The Business DR Contractual Program will also continue to explore different payment structures that are more performance and event based. The flexibility built into the contractual framework allows the Company to provide timely program upgrades and adapt to evolving customer market needs.

V. NEW DR PILOT

Q. Is the Company requesting funding for any DR Programs?

A. Yes. The Company is seeking $750,000 capital and $250,000 O&M included in Exhibit A-12 (AMG-1), Schedule B-5.5 and Exhibit A-95 (AMG-2), respectively for its proposed Whole Home Optimization Demand Response pilot, that will test customer-owned smart home energy management systems, battery storage, and load management devices. The

costs associated with testing these technologies include technology demonstrations for the various customer types. Load Management Devices will require an investment of $200,000, multifamily whole unit optimization will require $200,000, single-family whole home optimization will require $150,000, and smart analytics and aggregation through whole home smart optimization will require $200,000. Additionally, evaluation, incubation, and labor costs are estimated at $250,000.

Q. Please describe the proposed pilot.

A. The Company's proposed Whole Home Optimization Demand Response pilot will allow the Company to test how customers respond to and interact with energy usage and demand analytics, customer-controlled responses and behavior, and aggregation of resources within their home using a whole home optimization approach.

The Company is seeking to test this technology specifically with its residential customers given the past implementation of Time-of-Use ("TOU") rate structures (RSP 1001, RSH 1040, and RPM 1050), to quantify energy savings impacts, and to understand the barriers customers face with adopting DERs in the home, including battery storage and electric vehicles, to shift energy off-peak.

The Company will work with implementation contractors, third-party evaluators, and software and hardware vendors to install and test a variety of available technologies to assess cost-effectiveness, demand reduction, energy waste reduction, customer interest, and technical integration feasibility.

The pilot is discussed in detail in Exhibit A-182 (AMG-3).

VI. SUMMARY

Q. Please summarize your direct testimony.

A. The Company projects $34.63 million in O&M expenses in the test year and $1.56 million in capital in the test year to support DR programs, including the pilot proposal. Details on the DR revenue requirement are supported by Company witness Daly and details on the DR surcharge are supported by Company witness Connolly.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

ALEX M. GAST

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Alex M. Gast, and my business address is One Energy Plaza, Jackson, MI 49201.

Q. Are you the same Alex M. Gast who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Joshua S. Towslee and Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United ("MEIU") witness Brett Sproul.

Staff Witness Towslee

Q. Starting on page 3, line 15 of his testimony, Staff witness Towslee has recommended the Company include the following items related to the Whole Home Optimization Demand Response ("DR") in its relevant filings during the pilot period: pilot costs, allocation of remaining funds, energy savings, technologies that will be tested and evaluated, cost-effectiveness assessments, and plans for participants once the pilot period ends. How does the Company respond?

A. The Company is supportive of this request by Staff and will include these items related to the Whole Home Optimization Pilot in annual DR Reconciliations going forward. If the pilot is approved and the Commission adopts Staff's recommendation.

Q. Starting on page 5, line 4 of his testimony, Staff witness Towslee recommended that the Company's proposed changes to the DR regulatory construct be deferred to the Commission's decision in Case No. U-21637. How does the Company respond?

A. The Company appreciates Staff's support for amending the related construct, however, remains concerned about the timing of the changes in relation to the upcoming 2026 DR filing that would reconcile the 2025 plan and introduce the 2027 plan. Because the Company's proposed change would be included in its 2026 DR filing, which takes place in May, the Company would need a decision sooner than that anticipated in Case No. U-21637, which has no definitive schedule for a Commission order. If the Commission were not to decide on this issue in the instant case or the pending 2024 DR Reconciliation case (Case No. U-21906), the Company would likely not be able to file planned DR costs for 2027 and would have to include planned DR spend in its subsequent electric rate case filing.

MEIU Witness Sproul

Q. Starting on page 20, line 7 of his testimony, MEIU witness Sproul has recommended the Company's proposals to reduce the customer demand savings levels for both Critical Peak Pricing ("CPP") and Peak Time Rewards ("PTR"), reduce the PTR bill credit, and discontinue the PTR program customer enrollment incentives be rejected. Overall, how does the Company respond?

A. The Company disagrees. Accurate savings values and increasing program cost-effectiveness are both important for all DR programs to ensure the Company's DR portfolio is predictable and maintains cost-effectiveness. The Company's proposal to reduce customer demand savings levels for CPP and PTR aims to align expected demand reduction with actual demand savings. Relying on the higher numbers to predict the benefit CPP and

PTR provide during an event creates risk for the Company if those higher values cannot be attained. If expected demand reduction is not aligned with actual demand savings it would negatively impact the Company's ability to economically serve the load The Company agrees with MEIU witness Sproul that the programs have changed since the 2022 Cadmus study, but this only increases the need to reduce expected demand savings per customer, as higher enrollment means the Company would expect larger total actual demand savings during an event.

Q. How does the Company respond to MEIU witness Sproul's specific recommendations for the PTR?

A. Similar to the discussion above, given the increase in program enrollment, the Company's proposal to reduce the PTR bill credit aims to reduce the total cost of calling an event, which would be material without the Company's proposal. Discontinuing the PTR customer enrollment incentive also contributes to DR portfolio cost-effectiveness and limits enrollment, making future events more cost-effective. If there was a need to boost enrollment, the Company could offer an enrollment incentive at that time.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Thank you, Your Honor.

Next is company witness Brittani A. Gray who had direct testimony consisting of a cover page and seven pages of questions and answers. Ms. Gray sponsored Exhibit A-96 and her Exhibit A-16 also has other witnesses sponsoring schedules.

THE COURT: Are there any objections to the admission of this testimony or this exhibit.

Hearing none. The direct testimony of Brittani Gray is bound in the record and Exhibit A-96 is admitted.

(At 2:55 p.m., Exhibit A-96 is admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

BRITTANI A. GRAY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Brittani A. Gray, and my business address is One Energy Plaza, Jackson, Michigan, 49201.

QUALIFICATIONS

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Tariff Analyst in the Rates and Regulation Department.

Q. Please describe your educational and professional experience.

A. In January 2010, I was hired by Consumers Energy as a Customer Service Representative within the Company's Customer Contact Center. In April 2013, I joined the Virtual Contact Center's Customer Value Initiative Team researching industry best practices. In February 2014, I joined the Business Center within the Business Customer Care Department and became a subject matter expert in Complex Billing and Commercial & Industrial rates. In April 2019, I was promoted as a Business Customer Solutions Account Manager where I worked directly with customers on a variety of reactive requests related to Complex Billing, Rates and Tariffs, Field Operations, Outage and Reliability, and Project Support. I ensured any questions, concerns, or requests were addressed and resolved to provide the best possible customer experience. In May 2023, I joined the Rates and Regulations Department as a Tariff Analyst and in May 2024, I was promoted to Senior Tariff Analyst. My primary responsibilities include tariff filings, developing tariff exhibits for rate cases, rate implementation, complex billing, and preparing rate and monthly bill comparisons. In addition, I have attended Michigan State University's Institute of Public Utilities (IPU) Accounting and Rate Making Course.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

Yes. I have filed direct testimony in the following cases:

Case No. U-21374	Voluntary Green Pricing programs; and
Case No. U-21585	Electric General Rate Case.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to present the Company's proposed tariff language changes to its electric rate schedules.

EXHIBITS

Q. Are you sponsoring any exhibits in this case?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-96 (BAG-1)		Summary of Tariff Changes; and
Exhibit A-16 (BAG-2)	Schedule F-5	Proposed Electric Tariff Sheets (M.P.S.C. No. 14 Redlined Version).

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. Please explain Exhibit A-96 (BAG-1) – Summary of Tariff Changes.

A. Exhibit A-96 (BAG-1) provides a summary and explanation of the changes proposed in this filing to the tariffs in the Company's Electric Rate Book.

Q. Please describe Exhibit A-16 (BAG-2), Schedule F-5, Proposed Electric Tariff Sheets (MPSC No. 14 Redlined Version).

A. Exhibit A-16 (BAG-2), Schedule F-5 contains all proposed changes to the Company's current electric tariffs in the Rate Book for Electric Service (M.P.S.C. No. 14 – Electric),

presented in redlined format. Existing tariff language proposed for deletion is shown with red strikethrough formatting, while new proposed language is indicated by blue underlined and italicized formatting. Some changes are discussed in the testimony of other Company witnesses, such as the rationale for price changes to the Company's electric rate schedules, which are supported by the Company's rate design witness, Laura M. Connolly.

Q. Please explain the proposed changes to New Service Connection fees.

A. Supported by Company witness Jennifer M. Partlan, the Company proposes to introduce an overhead service connection fee and update the existing underground service connection fee for Residential and General Service Customers. The changes are based on inflation rates and a three-year average length of service.

Q. Why is the Company proposing to introduce an overhead service connection fee?

A. The Company proposes to introduce a service fee for overhead connections that mirrors the proposed fee for underground connections. This change is intended to promote fairness by applying a uniform fee structure for new service installations, regardless of the connection type. Additionally, the proposal supports customer adoption of the more reliable underground option and aligns with the Company's Reliability Roadmap.

Q. Why is the Company proposing to adjust the underground service connection fees?

A. The Company is proposing to revise the current underground service connection fee to reflect inflationary cost increases that have occurred since the fees were last updated in Case No. U-9346 approved for service rendered on and after August 6, 1993.

Q. What calculations were used to determine the proposed service connection fees?

A. The proposed fees are based on a three-year average service connection length of 132 feet. To simplify the structure and better reflect current economic conditions, the Company

proposes replacing the existing per-foot charge with a flat fee of $1,300 for Residential Customers and $2,200 for General Service Customers. These proposed amounts were derived by applying the cumulative inflation rate over the past 31 years to the current per-foot charges and multiplying by the average service length. The calculation is provided below, supported by Company witness Partlan, whose testimony addresses the associated Low Voltage Distribution ("LVD") work and cost considerations for New Business.

- Residential:
  - Current Fees: $4.50/ft ($9.93/ft cost of inflation)
  - Proposed Fees: ($9.93*132) = $1,310.76
- General Service:
  - Current Fees: $6.50/ft ($16.88/ft cost of inflation)
  - Proposed Fees: ($16.88*132) = $2,228.16

Q. Please explain the proposed changes to Rule C5.4 Shut Off Protection Plan.

A. The Company proposes to increase the eligibility for the Shut Off Protection Plan ("SPP") from 200% to 400% of the federal poverty level. This change aims to provide support for a larger segment of moderate-income customers as outlined by Company witness Jessica R. Byrom.

Q. Please explain the changes to Rule C5.5 Non-Transmitting Meter Provision.

A. Eligible customers who elect a non-transmitting meter are served under the applicable rates in accordance with Rule C5.5, Non-Transmitting Meter Provision. Currently, two potential upfront charges apply, depending on when the customer provides notice to opt out. However, because the Company has completed the initial deployment of Advanced Metering Infrastructure ("AMI") meters for all customers who have not opted out, the distinction between early and late opt-outs is no longer necessary. Accordingly, the Company proposes to simplify the fee structure by implementing a single upfront charge for all customers who elect to opt out, regardless of timing. This change is intended to

promote consistency and fairness in the administration of the provision, while maintaining the existing eligibility criteria as defined in the tariff.

Q. Is the Company proposing any other changes to its AMI Opt-Out Charges?

A. Yes. Supported by Company witness Michael P. Kelly, the Company is proposing updated AMI opt-out charges based on a re-evaluation conducted in compliance with the Commission's directive in the Final Order in Case No. U-21585. The proposed charges, as calculated by Company witness Kelly, are as follows:

- Up Front Charge: $216.22
- Monthly Charge: $3.09

Q. Please explain the removal of Sheet Nos. C-50.00 – C-51.00 and D-80.00.

A. The Company proposes to remove the tariff sheets associated with the Experimental Advanced Renewable Program ("EARP")–Anaerobic Digestion Program ("AD Program") because the program is closed to new participants and has had no active customers since May 2023. The removal reflects the current status of the program and ensures the tariff remains accurate and up to date.

Q. Please explain the changes to General Service Secondary Time of Use Rate GSTU.

A. The Company is proposing to revise the availability of Rate GSTU to clarify that customers may participate in Demand Response ("DR") programs while taking service under this rate.

Q. Why is the Company proposing to modify the availability of Rate GSTU?

A. Full Service customers taking service under Rate GSTU are currently eligible to participate in DR programs, as outlined on Sheet No. D-10.00, Rate Categories and Provisions. The proposed revision is intended to clarify the eligibility within the GSTU tariff itself, ensuring consistency and transparency in how the rate is administered.

Q. Please explain the Company's proposed modification to the Aggregate Peak Demand Service ("GAP") provision.

A. The Company is proposing to revise the GAP provision that allows for discretionary enrollment of customers who may not meet all of the stated eligibility criteria. Specifically, the Company seeks the ability to consider participation by customers with fewer than seven accounts and/or accounts with a lower average On-Peak Billing Demand than the current 250 kW demand threshold. This flexibility would be exercised solely at the Company's discretion and would not alter the fundamental structure or intent of the provision.

Q. What is the purpose of this proposed change?

A. The purpose of this change is to provide the Company with administrative flexibility to accommodate unique customer circumstances that may not fit neatly within the existing eligibility framework. In some cases, customers may narrowly miss one of the criteria but still be appropriate candidates for participation. This change allows the Company to evaluate such situations and make reasonable determinations without requiring a formal tariff revision each time.

Q. Will this change affect other customers or the overall administration of the tariff?

A. No. This change does not alter the structure or pricing of the GAP provision and is not expected to impact other customers. It simply provides the Company with the ability to consider exceptions in limited circumstances, which can improve customer service and responsiveness without compromising the integrity of the tariff.

Q. Please explain the changes to the Large Economic Development Rate LED.

A. The Company proposes adding a Power Factor adjustment to Rate LED. This adjustment is similar to the recently approved Power Factor adjustment for Rates GP, GPD, GPTU,

and EIP in Case No. U-21585, but with an increased penalty band – up to an average Power Factor of 0.909 – compared to the penalty bands for these other rates. Additionally, the Company proposes including a facilities allowance. Further details are provided by Company witness Connolly.

Q. Are there any other tariff changes being proposed by the Company?

A. Yes. The remainder of the Company's proposed tariff changes are described in Exhibit A-96 (BAG-1), Summary of Tariff Changes. This exhibit provides a summary and explanation of all the tariff changes being proposed by the Company in this case.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MR. GENSCH: Thank you, Your Honor.

Next is company witness, Kendra K. Grob who had direct testimony consisted of a cover page and 31 pages of questions and answers. Ms. Grob also sponsored Exhibits A-97, A-98, A-99, and confidential Exhibit A-101.

THE COURT: Are there any objections to the admission of this testimony of these exhibits?

Hearing none. The direct testimony of Kendra Grob is bound in the record, Exhibits A-97 through A-99 are admitted to the public record and Exhibit A-100 is admitted to the confidential record.

(At 2:56 p.m. Exhibits A-97 through A-99 admitted to the public record and Exhibit A-100 is admitted to the confidential record)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

KENDRA K. GROB

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Kendra K. Grob, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your current position with Consumers Energy?

A. I am currently the Senior Manager, Benefits.

Q. What are your responsibilities as Senior Manager, Benefits?

A. I am responsible for the design, implementation, and administration of the Company's retirement and health care plans, and our department oversees the benefit plans for employees and retirees. In the retirement benefits area, the Company contributes to the cost of the Pension Plans, the Defined Company Contribution Plan ("DCCP"), and the 401(k) Employees' Savings Plan ("ESP"). My responsibilities include designing, reviewing, and administering competitive, cost-effective, quality plans that attract and retain qualified employees to serve customers. These plans aim to provide a portion of an employee's retirement income, along with social security benefits and personal savings.

In the benefits area, the Company contributes to the cost of health care plans (medical, prescription drug, dental, including Health Savings Accounts ("HSAs") and Health Care Flexible Spending Accounts ("HCFSAs")), life insurance, and Long-Term Disability ("LTD") insurance. Our department also designs, reviews, and administers these health care and other benefit plans to ensure they are competitive, cost-effective, and of high quality for employees and retirees, helping to attract and retain qualified employees to serve customers. Additionally, the Company offers several benefit plans at group

discounted rates, requiring employees to pay the full cost of the coverage elected. These voluntary plans include accidental death and dismemberment insurance, health care and dependent care flexible spending accounts, vision insurance, and dependent term life insurance. In 2024, the Company added hospital indemnity, critical illness, and accident benefits. These insurance plans help attract and retain qualified employees by protecting them and their families from significant financial loss in various areas. Our team is also responsible for Absence Management, Workers' Compensation, and Occupational Health programs, as well as the total well-being program, Live Well 365, which motivates employees to manage their overall well-being.

Q. What is your formal educational experience?

A. In 1998, I graduated from Siena Heights University in Adrian, Michigan with a Bachelor of Business Administration degree. I hold a Professional certification in Human Resources from HR Certificate Institute ("HRCI") and the Society of Human Resource Management ("SHRM").

Q. Would you please describe your previous work experience?

A. In 1995, I began my career focused on human resources at Health Care Solutions, Inc. as a Human Resources Manager. In this role, I was responsible for the Human Resource Management of the corporate office in Ann Arbor, MI. Also, I had leadership responsibility over all field Human Resource Managers. In addition to this responsibility, I managed all health care and retirement plans for the company. It was my sole responsibility to ensure employees were enrolled in the correct plans and provide any administration to the plan. This also included plan audits and decision making in determining the best vendors.

In 2007, I began working for Amcor Rigid Packaging as a Senior Benefits Specialist. My area of responsibility was retirement plans, disability, and life insurance plans. In this role, I was responsible for the relationship with vendors and the administration of plans for our employees. I was the primary vendor contact for these areas and was heavily involved in all Request for Proposal processes in choosing vendors. While in this position, I sat on the Retirement Committee as the Secretary and took part in plan design and fund selections for both the pension and the savings plan.

In 2020, I joined Consumers Energy as Manager, Retirement Plans. My responsibilities included complete oversight for the Company pension and savings plans (401k). In this role, I ensured the Company provides retirement benefits to active and retired employees while maintaining accurate legal compliance with the Internal Revenue Service.

In March 2024, I was promoted to Senior Manager, Benefits. In this role I continued complete oversight for the Company pension and savings plans (401k) with the addition of assuming responsibility for health and welfare benefits.

Q. Are you a member of any professional societies or trade associations?

A. I am professionally certified as a Human Resources Professional through both SHRM and HRCI.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide support for the Company's costs related to the electric business portion of retirement, health care, life insurance, LTD plans, and other benefits provided to its employees and retirees. In Part I of my direct testimony, I will address the retirement benefits plans. In Part II of my direct testimony, I will address

health care, life insurance, LTD plans, and other benefits, which include absence management and educational assistance programs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-97 (KKG-1)	Summary of Actual and Projected Benefits O&M Expenses for the Year 2024 and Test Year Twelve Months Ending April 30, 2027;
Exhibit A-98 (KKG-2)	CMS Energy – Pension Plans A and B - ASC 715 Pension Expense Estimates ($ millions);
Exhibit A-99 (KKG-3)	CMS Energy - ASC 715 OPEB Expense Estimates ($ millions); and
Confidential Exhibit A-100 (KKG-4)	CMS Energy – Actuarial Letter of Support for 2025 Year Projections.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please describe Exhibit A-97 (KKG-1).

A. Exhibit A-97 (KKG-1), page 1, summarizes 2024 actual expenses through the 12 months ending April 30, 2027, projected electric Operating and Maintenance ("O&M") expenses for the Company's retirement and insurance benefit plans offered to employees and retirees. On this exhibit, column (a) provides a program description of the O&M expense category. Column (b) provides the actual expense in 2024 for each plan. Column (c) provides the projected expense for the 12 months ending April 30, 2027. Page 2 provides information on inflation factor projections and adjustments using the methods discussed in this testimony and included in column (i). Column (j) is the projected test year O&M expense and is the sum of columns (b) + (d) + (f) + (h) + (i).

Q. Please describe Exhibits A-98 (KKG-2), A-99 (KKG-3), and Confidential Exhibit A-100 (KKG-4).

A. Exhibits A-98 (KKG-2) and A-99 (KKG-3) provide the Aon actuarial projections for Pension and Other Post Employment Benefit ("OPEB") expenses for the years identified. Both the Pension and OPEB projections in these exhibits provided by the Aon actuaries are from the year-end 2024 measurement of the Pension and OPEB plans and with current market conditions as of December 31, 2024. A letter from the actuary regarding the accuracy and completeness of the projections is included in Confidential Exhibit A-100 (KKG-4).

I. RETIREMENT BENEFITS PLANS

Q. Which retirement benefits are you addressing in this section of your direct testimony?

A. I am addressing the Pension Plans, DCCP, and ESP. These expenses are shown on Exhibit A-97 (KKG-1), page 1, lines 1 through 3.

Q. How are the Pension Plans, DCCP, and ESP expenses that are common to electric and gas operations allocated to the electric portion of the business?

A. Expenses common to both the electric and gas operations associated with the Pension Plans, DCCP, and ESP are allocated based on the relationship of employee labor dollars charged to electric operations compared to the labor dollars charged to both electric and gas operations. These allocations studies are performed by the Accounting Department. The electric portion of the O&M expense for these plans is shown on Exhibit A-97 (KKG-1), page 1.

Pension Plans

Q. Would you please explain your Exhibit A-97 (KKG-1), line 1, which begins with ($51,785,000) in 2024?

A. Exhibit A-97 (KKG-1), page 1, line 1, shows the actual 2024 pension expense and the projected expense for 12 months ending April 30, 2027, attributable to the electric portion of the utility operations.

Q. How does the Company determine its expense for the Pension Plans?

A. The pension expense is determined using actuarial analysis that is performed in accordance with Accounting Standards Codification ("ASC") 715. Consumers Energy follows Generally Accepted Accounting Principles ("GAAP") for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodology and assumptions required to properly calculate and account for pension expense which includes evaluation of market conditions at each of the Pension Plan's measurement dates. In addition, the Company's auditor rigorously reviews the process to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of pension expense. Pension expense is determined based on actuarially reviewed employee census data, plan provisions, plan assets, and certain other assumptions. Year-end disclosure information is also produced, based on these accounting standards, to show a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this electric rate case, the Pension Plans were measured in January for year-end December 31, 2024.

Q. What are the components of the annual pension expense under ASC 715?

A. There are four components of the annual pension expense: (i) service cost; (ii) interest cost; (iii) expected return on plan assets; and (iv) amortization of gains or losses, prior service

costs or credits, and any transitional amounts. The plan's service cost represents the value of the benefits earned during the year. This is determined individually for each participant based on their specific employee demographics. The interest cost represents interest on the plan's liabilities due to the passage of time. There is also an assumption made for the expected return on plan assets. The expected return on plan assets each year reduces the plan's annual expense. The expected return assumption is reviewed periodically by the plan's actuary, the plan's investment advisor, and the Company, and is intended to be a long-term assumption based on the best estimate of the long-term expected investment earnings of the plan assets. The last component of plan expense is amortization of various plan experiences that were not anticipated by the plan's actuarial assumptions. For example, plan experience gains or losses and plan design changes that would be amortized are included as a part of this component of plan expense. The amortization can be either credits or costs.

To calculate the plan's total pension benefit obligation and annual ASC 715 expense, the actuary uses several assumptions including discount rate, mortality table, salary change, expected return on plan assets, and expected future contributions needed to avoid benefit restrictions under the Pension Protection Act. The methods used to set assumptions are generally unchanged annually, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary.

Q. Please describe how the discount rate is set each year.

A. The Company relies on its actuary's discount rate setting model. The model uses current high-quality bonds to match the Pension Plan's cash flows using statistical techniques that

create a yield curve that determines the effective discount rate for all maturities of pension payments. The model itself does not change annually, but the discount rate typically will be updated based on the most current market conditions.

Q. Please describe how the expected return on plan assets is set each year.

A. The Company uses future expected capital market assumptions, asset allocation information, and other resources provided by its consultants, which may include survey data and analysis of the Pension Plan's asset allocation. The expected return assumption is based on long-term expectations and not short-term returns. The Company uses all this information to establish an expected return on plan assets assumption that best estimates its expectation. While this assumption is reviewed for each plan measurement, it may or may not be updated annually depending on the information that is presented.

Q. Does the Company apply Accounting Standard Update ("ASU") No. 2017-07 Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this case?

A. Yes, the Company adopted the ASU No. 2017-07 standard as of January 1, 2017, and has applied the Standard in this case for both Pension and OPEB. This ASU No. 2017-07 standard allows only the service cost component of expense to be recorded as an operating expense and all other benefit-cost components are to be recorded outside operating income. The Standard also allows only service costs to be capitalized, while all other cost components are recorded to net income immediately.

Q. Please describe the development of the Pension Plans' expense shown on Exhibit A-97 (KKG-1), page 1, line 1, which begins with ($51,785,000) for 2024.

A. The annual pension expense shown on Exhibit A-97 (KKG-1), page 1, line 1, for the electric utility is based upon Aon's actuarial determination of each plan's total expense for that year in accordance with ASC 715 and includes plan administration fees, aggregated for total pension expense. The Consumers Energy pension expense determined by Aon plus administration fees are allocated to the electric and gas portions of the utility using the Accounting Department methodology described earlier. This allocation resulted in the actual electric utility O&M expense for Pension of ($51,785,000) in 2024, and projected expense of ($45,156,000) for the 12 months ending April 30, 2027. Exhibit A-97 (KKG-1), page 2, line 1, column (i), compares the Aon actual calculation of expense with the 2024 actual expense, as adjusted for 2025, 2026, and 2027 inflation, to calculate other adjustments.

Q. Have there been any significant plan design changes to the Pension Plan in recent years?

A. Yes. The Company split its Pension Plan into two plans as of January 1, 2018. Generally, all participants who were employees of the Company on August 1, 2017, were included in Pension Plan A. All other participants, including any Cash Balance participants, were assigned to Pension Plan B. No changes to participant benefits occurred because of this change. The Company decided to make this change to help manage expenses of the Pension Plans by extending the amortization period for the inactive group and enabling the mitigation of Pension Benefit Guarantee Corporation premium variability.

Q. Did the Company make any cash contributions to the Pension Plans in 2024?

A. No, the Company did not contribute to either plan in 2024.

Q. Will the Company make any cash contributions to the Pension Plans in 2025?

A. No cash Pension Plan contributions are required in 2025 to avoid benefit restrictions. Any contributions the Company elects to make during these periods of time will depend upon future decisions of the Company regarding funding policy, the future value of plan assets and liabilities, and any potential legislative guidance or changes.

Q. Why did the pension expense increase for the projected test year from 2024?

A. The Pension expense increased due to lower-than-expected asset returns in 2024.

Q. Have any changes recently been made to the Pension Plans' benefits?

A. Effective November 1, 2020, the Company changed the unreduced early retirement age from 62 to 61 for the Company's pension union eligible employees. This benefit enhancement allows for the Company to continue to retain current union pension eligible employees since they can now retire one year earlier but not lose any percentage of their pension benefit and was very well received. The additional changes in the projected pension expense estimates from 2024 to the 12 months ending April 30, 2027, are primarily the result of economic conditions external to the Pension Plans over which the Company has no control.

DB Pension/OPEB Volatility Mechanism ("VM")

Q. Please describe the DB Pension/OPEB VM that the Company is proposing.

A. The Company requests the ability to continue its implementation of a DB Pension/OPEB VM, previously authorized by the MPSC in Case Nos. U-21585 and U-21389. The sensitivity of DB Pension/OPEB expenses to changes in asset returns or other assumptions

creates a significant potential for large variability in future expenses. Customers benefit from a mechanism that eliminates the risk of future volatility in expense. Without a mechanism, there could be substantial, unanticipated swings in the DB Pension/OPEB expense. The proposed mechanism, which mirrors the mechanism that has existed since 2023, would protect customers from this volatility by allowing the Company to defer annually the difference between the DB Pension/OPEB expense included in rates versus the actual annual DB Pension/OPEB expense recorded by the Company pursuant to ASC 715.

Q. Is the mechanism symmetrical?

A. Yes. Under the mechanism, if the actual annual DB Pension/OPEB expense is less than the expense approved in rates, the difference would be recognized as a regulatory liability and amortized over 10 years starting the following January. Similarly, if actual annual DB Pension/OPEB expense is greater than the expense approved in rates, the difference would be recognized as a regulatory asset and amortized in the same manner. Any amortization of these regulatory assets or liabilities would be included in future general rate cases. The mechanism is not only fair but similar mechanisms have been approved by the Commission for other utilities in contested cases. See, e.g., MPSC Case No. U-21297, December 1, 2023 Order, pages 222-224; MPSC Case No. U-21291, November 7, 2024 Order, page 160.

Q. Please describe the Pension VM Deferral on Exhibit A-97 (KKG-1), page 1, line 7, column (b), which begins with $10,729,000 for 2024.

A. Per the Settlement Agreement in Case No. U-21224, the Company was authorized to defer actual DB Pension expense different than the approved annual amount of ($29,700,000) starting in 2023. In the Case No. U-21389 Order, the Company was authorized to defer the

actual DB Pension expense, which different than the approved annual amount of ($43,327,000) starting in March 2024. In 2024, the DB Pension expense was lower than the approved amounts as shown on Exhibit A-97 (KKG-1), page 1, line 1, column (b), of ($51,785,000) for 2024. The Company compared the authorized amount for two months, totaling $4,950,000, by taking the annual authorized amount in Case No. U-21224 ($29,700,000), dividing it by 12, and multiplying by two months for January and February 2024. For the months of March to December 2024, the Company compared ten months of authorized expenses totaling ($36,106,000). This was calculated by taking the 12 months authorized amount in Case No. U-21389 ($43,327,000), dividing it by 12, and multiplying by ten months. Adding the two-month authorized amount of ($4,950,000) to the ten-month amount of ($36,106,000) results in a total authorized amount for 2024 of ($41,056,000). The Company recorded the difference between the actual DB Pension expense and the approved rate expense for the Pension VM for the year 2024. The Pension VM deferral of $10,729,000 resulted in an increased expense for 2024, and the Company consequently recorded a Pension VM regulatory liability of $10,729,000.

Q. Please describe the Pension VM Amortization on Exhibit A-97 (KKG-1), page 1, line 9, column (c), which begins with ($1,912,000) for 12 months ending April 30, 2027.

A. The Pension VM amortization includes deferred amounts being amortized from 2023 to 2025. These deferred Pension VM amounts are being amortized over a 10-year period, consistent with the approach used in Case Nos. U-21585, U-21389, and U-21224.

Q. Please describe the OPEB VM Deferral on Exhibit A-97 (KKG-1), page 1, line 8, column (b), which begins with $3,579,000 for 2024.

A. Per the Settlement Agreement in Case No. U-21224 the Company was authorized to defer actual OPEB expense different than the approved annual amount of ($65,700,000) starting in 2023. In the Case No. U-21389 Order, the Company was authorized to defer actual DB Pension expense different than the approved annual amount of ($39,608,000) starting in March 2024. In 2024, the OPEB expense was lower than the approved amounts as shown on Exhibit A-97 (KKG-1), page 1, line 5, column (b), of ($47,536,000) for 2024. The Company compared two months authorized of ($10,950,000), taking the authorized amount in Case No. U-21224 ($65,700,000) dividing by 12 and times by two months for January and February 2024 and for months March to December 2024, the Company compared ten months of authorized ($33,007,000), taking the 12-month authorized amount in Case No. U-21389 ($39,608,000) dividing by 12 and times by ten months. Taking the ($10,950,000) plus ($33,007,000) gives the total authorized amount for 2024 of ($43,957,000). The Company recorded the difference between the actual OPEB expense and the approved rate expense for the OPEB VM for the year 2024. The OPEB VM deferral of 3,579,000 resulted in an increase expense for 2024, and the Company consequently recorded a Pension VM regulatory liability for $3,579,000.

Q. Please describe the OPEB VM Amortization on Exhibit A-97 (KKG-1), page 1, line 10, column (c), which begins with $1,813,000 for 12 months ending April 30, 2027?

A. The OPEB VM amortization includes the deferred amounts being amortized for the years 2023 to 2025. The deferred OPEB VM is being amortized over 10 years which is consistent with how the VM in Case Nos. U-21585, U-21389, and U-21224 operated.

DCCP

Q. Does the Company provide an alternative qualified benefit plan to the closed Pension Plans for employees hired on and after September 1, 2005?

A. To stay competitive by offering a benefits package that attracts and retains qualified and talented employees for the benefit of the customer, the Company replaced the Final Average Pay and Cash Balance versions of the qualified DB Pension Plan with the qualified DCCP. This change applied to all existing Cash Balance participants and newly hired employees starting from September 1, 2005.

Q. Are there any employees included in the DCCP that were hired before September 1, 2005?

A. Employees hired between July 1, 2003, and August 31, 2005, who were covered under the Cash Balance version of the defined benefit DB Pension Plan, became participants in the DCCP as of September 1, 2005. Concurrently, additional pay credits under the Cash Balance version of the defined benefit DB Pension Plan were discontinued for this specific group of employees.

Q. Will the Cash Balance version of the DB Pension Plan accept any new employees as participants?

A. Similar to the Final Average Pay DB Pension Plan, the Cash Balance version of the DB Pension Plan now has a limited group of participants. Over time, this group will gradually decrease until there are no longer any employees or retirees covered under this plan.

Q. Please provide a general description of the DCCP.

A. The DCCP currently provides an employer funded cash contribution as a percentage of an employee's base pay to the ESP—the percentages vary with years of service as described

below. No employee contribution is required to receive the employer contribution. All existing Cash Balance Plan employee participants and employees hired on and after September 1, 2005, participate in the DCCP as part of their retirement benefit package.

Q. Have any recent changes been made to the DCCP?

A. No changes have been made to the DCCP since 2021. Effective January 2021, for the Company's union employees, the DCCP provides an 8% to 10% (previously 5% to 7%) employer funded cash contribution based upon the union employee's service time with the Company. New union hires receive an 8% contribution, which increases to 9% when they have six years of service with the Company. When union employees reach 12 years of service, they receive a 10% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism. The increase in the union DCCP contributions was needed for the Company to remain competitive to attract qualified employees and retain talent that maximizes the efficiency of the Company's labor force and reduces costly turnover. Retaining trained, experienced, and motivated employees provides better service for customers.

The Company's exempt and non-exempt employees will continue to receive the DCCP which was effective in January 2016. The DCCP provides a 5% to 7% (previously 6%) employer funded cash contribution based upon the employee's service time with the Company. New hires receive a 5% contribution, which increases to 6% when they have six years of service with the Company. Employees receiving a 6% contribution before January 1, 2016, continue to receive their 6% employer contribution. When employees reach 12 years of service, they receive a 7% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism and helps

contain the cost of the DCCP for the benefit of the customer as all new hires starting in 2016 began receiving a 5% (previously 6% for new hires) employer contribution.

Q. Would you please explain your Exhibit A-97 (KKG-1), page 1, line 2, which begins with $14,774,000 in 2024?

A. Exhibit A-97 (KKG-1), page 1, line 2, represents the electric operations O&M expense related to the DCCP. The actual electric operations expense for this plan in 2024 was $14,774,000 as shown in column (b). Column (c) shows the projected electric DCCP expense of $16,507,000 for the 12 months ending April 30, 2027. DCCP costs are projected to increase using merit salary rate factors of 3.2% for 2024 through the 12 months ending April 30, 2027 If a DB Pension individual retires, the new person hired to replace their role is entered into the DCCP plan. For the projected years 2024 through the 12 months ending April 30, 2027, costs were split using 62% electric and 38% gas, with 52% capital on electric expenses.

Q. As a result of the revised eligibility requirements for participation in the Final Average Pay DB Pension Plan or the Cash Balance version of the DB Pension Plan, is it correct to say that all new hire employees who started on September 1, 2005, and after will receive their retirement benefits through plans that are referred to as defined contribution type plans?

A. Yes. The primary plans that will provide monetary benefits to this group of employees upon retirement are the DCCP and the ESP.

ESP

Q. Please explain briefly the ESP.

A. The ESP is a defined contribution retirement savings program funded by employee and employer contributions. A portion of employee contributions is matched by Consumers Energy. Prior to January 2022, the Company matched 100% of the employees' first 3% in contributions and 50% of the employees' next 2% in contributions to the ESP. Employee contributions beyond 5% were not matched by the Company. Consumers Energy's expense includes the Company's matching contributions, and the payments made to Fidelity Investments for administration of the program.

Q. Have any recent changes been made to the ESP?

A. Effective in January 2022, the Company match design has changed only for Salaried (exempt and non-exempt) employees to 100% of employee contributions up to 6% of the employee's salary. Employee contributions beyond 6% will not be matched by the Company. This change will help to keep the ESP cost and talent retention competitive in the market for the benefit of customers. The Union employees will continue receiving matching contributions of 100% for employee contributions of up to 3% of the employees' salary, and then 50% of employee contributions up to the next 2% of the employees' salary.

Q. Would you please explain your Exhibit A-97 (KKG-1), page 1, line 3, which begins with $11,396,000 in 2024?

A. Exhibit A-97 (KKG-1), page 1, line 3, represents the Company's electric operations expense related to the ESP. In 2024, the actual electric utility O&M expense for the ESP was $11,396,000. The electric utility's ESP O&M expense projected for the test year is $12,731,000. Savings Plan costs are projected to increase using merit salary rate type

increase of 3.2% for 2024 through the 12 months ending April 30, 2027. For the projected years 2024 through the 12 months ending April 30, 2027, costs were split using 62% electric and 38% gas, with 52% capital on electric expenses.

Q. Is the ESP employer matching program important to attracting and retaining employees?

A. Yes.

Q. Please explain why the ESP employer matching program is important to attract and retain employees.

A. The ESP with a match is commonly available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company, particularly considering the large number of retirement-eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Safe, reliable, and affordable electric service begins and ends with the Company's people. Investing in and retaining trained, experienced, and motivated employees' benefits customers as much as, or more than, any investment in infrastructure.

Q. Is the ESP employer match discretionary?

A. It is not discretionary for union employees. A provision in the Working Agreement ratified in 2005 with Operating Maintenance & Construction ("OM&C") and Virtual Call Center ("VCC") union employees assured these employees that the match would not be suspended

during their five-year contract. This provision has remained in effect for all following contracts up to and including the most recent five-year contract negotiated in 2020.

With respect to non-union employees, there is not a similar contractual prohibition against suspension. However, the ESP employer match is part of an overall competitive benefits package and employees depend upon its continuation so they can accumulate savings for retirement. This is a benefit that helps the Company attract and retain qualified and talented employees. From a practical standpoint, the Company views the employer match as non-discretionary.

II. HEALTH CARE, LIFE INSURANCE, LTD PLANS, AND OTHER BENEFITS

Q. Which health care and insurance benefits are you addressing?

A. I am addressing active employee health care (including HSAs and HCFSAs), life insurance, LTD plans, and other benefits of absence management and educational assistance, as well as retiree health care and life insurance plans. These expenses are shown on Exhibit A-97 (KKG-1), page 1, lines 4 through 6.

Q. Are the expenses for active employee health care (including HSAs and HCFSAs), life insurance, and LTD benefits determined in the same way as expenses for retiree health care and life insurance benefits?

A. No. The expenses for active employees are based upon the actual costs for these benefits that are expected to be incurred. The expenses for retirees are determined using actuarial analysis, which is performed by the Company's actuary, in accordance with ASC 715, formerly known as Financial Accounting Standards ("FAS") 106.

Q. How were the portions of active employee and retiree health care (including HSAs and HCFSAs), life insurance, LTD, and other benefits costs allocated to electric O&M expense determined?

A. The portion of the Company's total program expenses attributable to the electric utility was allocated based upon an annual study by the Accounting Department of the relationship of the number of employees in the electric utility to the total number of employees in both the electric and gas utility. The amount allocated to the electric utility is allocated between O&M expense and capital expense based upon the Accounting Department's formula. For the projected years 2024 through the 12 months ending April 30, 2027, costs were split using 56% electric and 44% gas, with 64% capital on electric expenses.

Active Health Care (Including HSAs and HCFSAs), Life Insurance, LTD, and Other Benefits

Q. Please describe the development of the active health care (including HSAs and HCFSAs), life insurance, and LTD expense levels that are shown on Exhibit A-97 (KKG-1), page 1, line 4, which begins with $29,089,000.

A. Exhibit A-97 (KKG-1), page 1, line 4, contains electric operations O&M expenses for the Company-funded benefit plans for active employees' health care (including HSAs and HCFSAs), life insurance, and LTD. The primary component of this expense is health care. Life insurance and LTD make up a much smaller portion of the expense. In 2024, the Company incurred an actual combined expense of $29,089,000 for health care, life insurance, and LTD for electric operations. The projected electric operation expense for these benefits for the projected test year is $33,385,000.

Q. What factors did you consider when projecting the test year's expenses for health care, life insurance, and LTD?

A. In projecting the test year's health care expenses, a number of factors were considered. The primary factors included current and projected inflation factors and a review of 2023 and 2024 national health trends/costs survey information provided by Willis Towers Watson ("WTW") actuarial consulting. Additional factors considered were the Company's medical and prescription drug carrier's health cost and claims experience expectations, the continuing rapid rise in availability and price of specialty prescription drugs, the current employee headcount, and the continuing cost increase impacts of national health care reform.

Q. Please explain how these factors were used to determine the Company's expected health care costs.

A. The Company has determined that using the inflation factors in this case will keep cost increases in line with inflation amounts. Exhibit A-97 (KKG-1), page 2, line 4, column (i), compares the projected test-year expense with the 2024 actual expense, adjusted for 2025, 2026, and 2027 inflation, to calculate other adjustments.

To further understand projected health care trends and costs, the Company and WTW reviewed expected health care trends and costs survey information from several large consulting firms. The Company and WTW also reviewed the Company's actual health care claims experience for employees and retirees in its health plans - Blue Cross/Blue Shield of Michigan ("BC/BS") and Express Scripts. This analysis of the Company's health plans revealed that the Company's workforce is older than the average age of the population insured by the BC/BS and Express Scripts plans, and as a result, the

Company's health plans have a higher expected utilization rate that is associated with an older covered population. Of the Company's current workforce, as of December 31, 2024, 47% of employees are over age 45; 32% are over age 50; and 18% are over age 55. The Company understands the older age of its workforce is expected to lead to a higher health care expense (primarily due to utilization of services).

To project future health care expenses, the Company and WTW also considered all the plan changes and programs that the Company has already implemented. These changes include sharing expected health care expense increases with employees through plan design changes like increased deductibles, copayments, and out-of-pocket maximums; increasing employee premium contributions for coverage; adding telehealth benefits to medical plans to lower expense; educating employees regarding the prudent and informed use of health care benefits; promoting use of preventive benefit services; promoting well-being through Live Well 365, which is integrated into all medical plan designs, that encourages and rewards plan participants for taking steps toward healthier lifestyles; securing favorable pricing on prescription drugs obtained through a large employer prescription drug collaborative; negotiating lower administrative fees with health plans and promoting enrollment into the Consumer Directed Health Plan ("CDHP"), a high deductible health plan which currently provides a Company contribution to the participant's HSA.

The Company and WTW also considered the specific changes to the union employees' health care plan benefits as negotiated in its 2020 through 2025 contracts, as well as changes made to the employees' health care benefit plans in 2021 described in detail later in this direct testimony. While there are very tangible savings in future health expenses to the Company and its customers as a result of these changes to employee health

care benefit plans, the Company believes a portion of these savings will be offset by increased health expenses incurred under national health care reform requirements (like Patient Centered Outcomes Research Institute fees, employer mandate shared responsibility administrative/reporting requirements, and potential penalties) as well as increased prescription expenses due to the availability of new and expensive specialty prescription drugs in the market. In addition, while the Company has taken numerous steps to control the rising expense of health care, many of these changes are one-time events that lower a plan's expense in that year to establish a new baseline moving forward, but future health care expenses then continue to increase from the new baseline expense.

Q. What are some of the reasons that health care costs are increasing at a level higher than general inflation?

A. There are a number of factors causing a higher rate of health care inflation than is reflected in the general Consumer Price Indexes ("CPIs"). Health care costs are expected to continue rising during the next several years due to an aging population living longer, additional utilization of services, price increases for services, new medical technology, cost shifts from government plans, mandated benefits coverage, rising provider malpractice premiums, new taxes on health claims, and rapidly escalating prescription drug prices including high prices for new, expensive specialty drugs. In addition, national health care reform will increase Company health care costs in the near term because of eligibility expansions (e.g. adult children to age 26), mandated benefits, removal of annual dollar limits, additional taxes, fees, penalties, new compliance/reporting requirements, and more government shifting of costs through Medicare and Medicaid expansion. These factors are all outside the control of Consumers Energy. Even with all the employee and retiree health

plan design and premium contribution changes made annually by the Company over a number of years, including the move to Live Well 365 program incentives, health care costs for the Company are still expected to continue increasing annually at a rate two to three times that of general CPI inflation. The assumption that healthcare costs will only increase at the general rate of inflation has not been the actual experience for many years and is not expected in the foreseeable future.

Q. Are increases in health care costs being experienced both locally and nationally?

A. Yes. While increases in health costs have moderated, both local and national health care costs continue to increase at rates greater than general CPI inflation.

Q. Are the significant increases in health care costs limited to active employees?

A. No. Health care costs are also increasing at a rate higher than the general CPI inflation for retirees for the same reasons cited earlier. In fact, retiree expenses are generally increasing at higher rates because of retirees' older ages and the resulting increases in utilization, particularly in the use of prescription drugs, including higher-priced specialty prescription drugs. The projected increases for active employee health care, like projected increases for retiree health care, are substantial, expected to occur, and largely beyond the control of the Company.

Q. Please describe the development of the expense levels for active employee life insurance and LTD costs included in Exhibit A-97 (KKG-1), page 1, line 4.

A. For 2025, the Company used inflation factors of 2.1%. In 2026, the Company used 2.4%, and for 2027, 2.4% was used. These expense estimates are reasonable as both life insurance and LTD premium costs are based on wage and salary levels and changes to this coverage throughout the year. The 2.1%, 2.4%, and 2.4% annual increases represent the normal,

expected merit increases in salaries/wages, increases due to salary adjustments made for job changes and promotions throughout the year, any upward movement in Company-paid life insurance coverage in each annual enrollment period, and increases in premium rates due to plan experience.

Q. What has the Company done to control the increase in active employee and retiree health care, life insurance, and LTD expenses?

A. The Company aggressively manages these benefit costs by analyzing costs and plan designs on an annual basis with our third party vendor, Willis Towers Watson. An example of recent changes made to manage the cost of the Company's health care plans offered to employees and retirees follows:

- Negotiated administrative fees and insured plan premium rates annually;
- Implemented health and disease management programs and added case management;
- Effective January 1, 2024, the Company made a plan design change in the Salaried Active Medical plans so the out-of-pocket limits for both Union and Salaried employees are now the same. In addition, changes were made to decrease premiums in the Salaried Active Community Blue Medical for active employees;
- Eliminated eligibility for Salaried Retiree Life – Employer Paid for those who retired on/after January 1, 2024. They may still participate in Retiree Life, but at their own cost; and
- Effective January 1, 2025 current Salaried and Retirees (Exempt/Non-Exempt) who are under age 65 as of 1/1/2025 and Spouses, and Survivors under age 65 were moved to the Via Benefits Health Insurance Marketplace (also known as the Individual and Family Plan Marketplace) and will no longer be eligible for coverage in the Blue Cross Blue Shield of Michigan/Express Scripts and Delta Dental retiree group healthcare plans. Dependents under the age of 26 and disabled dependents will remain on current active coverage with BCBS of Michigan.

Retiree Health Care and Life Insurance

Q. Would you please explain your Exhibit A-97 (KKG-1), page 1, line 5, for retiree health care and life insurance, which begins with ($47,536,000) in 2024?

A. Exhibit A-97 (KKG-1), page 1, line 5, reflects the actual 2024 and projected 12-month period ending April 30, 2027, electric utility retiree health care and life insurance expenses under ASC 715 (formerly known as FAS 106 expense). Each of the annual expense levels shown on line 5 is the total of two separate items which make up the total expense. Each year's expense contains an ASC 715 expense calculation and an actuarial services expense.

Q. How does the Company determine its ASC 715 expense for retiree health care and life insurance?

A. The expense is determined by using actuarial analysis that is performed in accordance with ASC 715. Consumers Energy follows GAAP for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodologies and assumptions required to properly calculate and account for retiree health care and life insurance expense which includes evaluation of market conditions at each of the plan's measurement dates. The calculations required by the accounting standards are performed at least annually by the plan's actuary, Aon, using information specific to the Company's OPEB plan. In addition, the Company's auditor rigorously reviews the process to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of retiree health care and life insurance expense (OPEB expense or formerly FAS 106 expense). The expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. Year-end disclosure information is also produced, based on these accounting standards, to provide a reconciliation of plan assets and liabilities at the

end of the Company's fiscal year. For this electric rate case, OPEB was measured in January for the year-end 2024.

Q. What are the components of the annual ASC 715 retiree health care and life insurance expense?

A. There are four components of the annual ASC 715 retiree health care and life insurance expense: (i) service cost; (ii) interest cost; (iii) expected earnings on plan assets; and (iv) amortization of gains and losses, prior service costs or credits, and any transitional amounts. Service cost represents one year's expected benefits earned by active covered employees. Interest cost represents interest on the plan's benefit obligation (its liabilities) due to the passage of time. There is also an assumption made for the expected rate of return on plan assets. This rate of return assumption is intended to be a long-term assumption based upon the best estimate of long-term expected investment earnings of the plan assets. The last component represents amortization of various plan experiences that were not anticipated by the actuarial assumptions.

In order to calculate the plan's total benefit obligation and annual ASC 715 retiree health care and life insurance expense, the actuary uses a number of assumptions including health care inflation trend rates, mortality table, the rate of employee retirements from the Company, the actual retiree health care and life insurance claims of the Company, a discount rate, and the expected contributions to the plan. The methods used to set assumptions are generally consistent, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary. The method used to set the discount rate and expected return on plan assets is the same as the method used for the pension plans, as discussed above.

Q. Are actuarial and administrative expenses included in Exhibit A-97 (KKG-1), page 1, line 5?

A. Yes. An annual expense for the actuarial and administrative services provided for the retiree health care and life insurance plans is included in Exhibit A-97 (KKG-1), page 1, line 5.

Q. What changes were made to the 2024 retiree health care plans?

A. In 2024, changes were made to decrease premiums in the Aetna Traditional Medical Plan for Retirees.

Q. What changes were made to the 2025 retiree health care plans?

A. Effective January 1, 2025, current Salaried and Retirees (Exempt/Non-Exempt who are under age 65 as of January 1, 2025 and Spouses, Dependents and Survivors under age 65 were moved to the Via Benefits Health Insurance Marketplace (also known as the Individual and Family Plan Marketplace) and will no longer be eligible for coverage in the Blue Cross Blue Shield of Michigan/Express Scripts and Delta Dental retiree group healthcare plans.

Q. Do the calculations for the retiree health care and life insurance expense follow the prescribed methodology of ASC 715?

A. Yes. The amounts are projected based on ASC 715 using information specific to the Company's retiree health care and life insurance plans. For this electric rate case, the OPEB Plan was measured in January 2025 for year-end.

Q. Has the Company applied the ASU No. 2017-07 Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this case for OPEB?

A. Yes, the Company adopted the ASU No. 2017-07 as of January 1, 2017, and has applied the Standard in this case for both Pension and OPEB.

Q. Please describe the development of the retiree health care and life insurance expense levels that are shown on Exhibit A-97 (KKG-1), line 5, which begins with ($47,536,000) in 2024.

A. The retiree health care and life insurance O&M expense level shown on line 5 for the electric utility is based upon Aon's actuarial determination of the plan's expense for that period in accordance with ASC 715 plus the cost for actuarial and administrative services related to these plans. Due to the retiree medical plan changes described earlier, the actual 2024 retiree health care and life insurance O&M expense for the electric utility was ($47,536,000). The projected electric O&M retiree health care and life insurance expense is ($48,867,000) for the test year. Exhibit A-97 (KKG-1), page 2, line 5, column (i), compares the Aon actual calculation of expense with the 2024 actual expense, as adjusted for 2025, 2026, and 2027 inflation, to calculate other adjustments.

Q. Why is the retiree health care and life insurance expense higher in 2024 and decreasing in the test year?

A. 2024 had lower-than-expected asset returns, which caused the lower projected expense, offset decrease in expense by the plan change benefit of moving current salaried and retirees (Exempt/Non-Exempt in the OPEB plan to VIA benefits in the test year.

Q. Would you please explain your Exhibit A-97 (KKG-1), page 1, line 6, for Other Benefits, which begins with $2,601,000 in 2024?

A. Exhibit A-97 (KKG-1), line 6, reflects the actual 2024 and projected 12-month period ending April 30, 2027 expenses for the electric utility benefits labor, the absence management program, the educational assistance program, and the employee assistance program. The adjustment in Exhibit A-97 (KKG-1), page 2, line 6, column (i), compares the projected test-year expense with the 2024 actual expense, adjusted for 2025, 2026, and 2027 inflation.

Q. Please explain why the absence management program is important to attract and retain employees.

A. Paid sick leave is needed to attract and retain employees. In 2014, the Company retained Reed Group, now known as Alight, as an external consultant to manage the Company's absence process. Since the relationship's inception, Alight has been able to improve the absence rate and provide a higher level of standardization, controls, and overall best practices to mitigate risk. Additionally, this streamlined approach ensures a procedure for all employees who need a leave of absence for any purpose.

Q. Please explain why the educational assistance program is important to attract and retain employees.

A. Educational assistance programs are widely available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. The Company offers partial tuition reimbursement to all employees. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company,

particularly considering the large number of retirement-eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Safe, reliable, and affordable electric service begins and ends with the Company's people. Investing in and retaining trained, experienced, and motivated employees benefits customers as much as, or more than, any investment in infrastructure. Educational assistance is just such an investment. It provides the opportunity for employees to continue their education, which further improves their skills to serve the customers of the Company.

Q. Please explain why the employee assistance program is important to attract and retain employees.

A. The Company offers employees, retirees, and dependents access to an assistance program which provides support to help resolve or manage problems that interfere with the ability to perform at work or in life. The employee assistance program provides a variety of on-line tools, face-to-face interactions, and telephone support. The program is designed to aid with any type of need, distraction, concern, or crisis. The employee assistance program provides legal support, financial information, work-life solutions, online services, and confidential counseling. The goal of the program is to improve the overall total well-being for all the Company's employees and retirees.

Q. Does this conclude your direct testimony?

A. Yes.

MR. GENSCH: Thank you, Your Honor.

We have the testimony of the company witness Megan L Hayward, consisting of a cover -- her direct testimony consisted of a cover page and -- and pages of questions and answers. Ms. Hayward also had rebuttal testimony consisting of a cover page and 29 pages of questions and answers. Ms. Hayward also sponsored Exhibits A-107 through A-111, and Exhibit A 2-18.

THE COURT: Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct and rebuttal test of Megan Hayward is bound into the record and Exhibits A-107 through A-111, and exhibit A-218 are admitted.

(At 2:57 p.m. Exhibits A-107 through A-111, and Exhibit A-218 admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

MEGAN L. HAYWARD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Megan L. Hayward, and my business address is 1945 W Parnall Rd, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently the Director of High Voltage Distribution ("HVD") System Planning.

Q. What are your responsibilities as Director of HVD System Planning?

A. My responsibilities as Director of HVD System Planning include oversight of capacity and new business engineering activities including planning and design services for the Company's high voltage electric distribution system, including HVD lines system, HVD and Low Voltage Distribution ("LVD") substations, and the Metro system.

Q. What is your formal educational experience?

A. I received a Bachelor of Science in Engineering degree in 2006 from Hope College and attended Michigan State University from 2006-2008 for a Master of Science in Engineering.

Q. Would you please describe your previous work experience?

A. I started my career with Consumers Energy in 2016 as a Civil & Structural Engineering Manager leading a team of engineers responsible for the statewide design of projects required for the capital investment plan at Generation facilities. In 2020, I moved to a new role as the Manager of Enterprise Resource Planning, supporting the development and visibility of long-term resource planning across the Company's utilities. In 2022, this role expanded, and I became the Director of Enterprise Resource and Workforce Planning,

which included setting the workforce planning objectives for the Company. I assumed my current role as the Director of HVD System Planning in 2024.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony provides an overview of the Company's HVD lines system, its HVD and LVD substations, and its Metro system; and associated capital investments to improve reliability and resiliency of those systems, while serving new customers to support economic development in the state of Michigan. I have organized my testimony as follows:

(i) A description of the Company's HVD lines system, HVD and LVD substations, Metro system, and System Protection assets, and the Company's strategy for investing in those systems;

(ii) A description of the HVD lines, HVD and LVD substations, and Metro capital programs and expenditures; and

(iii) A breakout of each of those capital programs' expenditures.

I also discuss and sponsor an exhibit explaining how the Company mapped substation and HVD line assets into voltage and other categories identified in the Electric Asset Categorization ("EAC") report used in the Cost-of-Service Study ("COSS") and discussed in more detail by Company witness Emily A. Davis.

Q. Are you the only Company witness addressing the Company's electric distribution strategy and investments?

A. No. Multiple witnesses are providing comprehensive support for the Company's electric distribution requests. Company witness Michael P. Kelly will provide an overview of the Company's electric distribution strategy and will discuss electric distribution Operating and Maintenance ("O&M") spending. Company witness Jennifer M. Partlan will provide an overview of the Company's historical and planned capital investments in the LVD lines system. Company witness Scott A. McPhail will provide an overview of the Company's

historical and planned capital investments in the Grid Automation Program. Company witness Daniel A. Schmoekel will provide an overview of the Company's historical and planned capital investments in streetlighting.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-107 (MLH-1)	Consumers Energy Electric Asset Management High Voltage Distribution (HVD) Pole Inspection Specifications;
Exhibit A-108 (MLH-2)	Pole Inspection Plan by HVD Line;
Exhibit A-109 (MLH-3)	Summary Projected Electric Capital Expenditures for the Bridge Period 16 Month Ending April 30th, 2026;
Exhibit A-110 (MLH-4)	Summary Projected Electric Capital Expenditures for the Test Year 12 Months Ending April 30th, 2027; and
Exhibit A-111 (MLH-5)	Electric Asset Categorization Mapping Document.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. How is your testimony organized?

A. Below is a Table of Contents which sets forth the subjects of my testimony.

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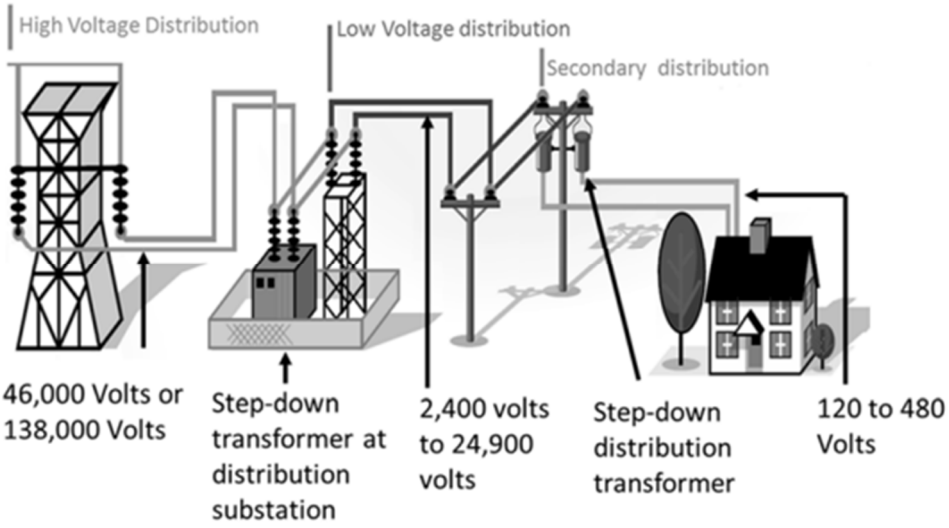
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I. EXECUTIVE SUMMARY

Q. What parts of the Company's distribution system will your testimony address?

A. As discussed by Company witness Kelly, the Company's electric distribution system is comprised of HVD, LVD, and Metro assets. The HVD and LVD systems are shown below in Figure 1. For purposes of this figure, Metro assets are essentially the same as LVD distribution assets.

FIGURE 1
HIGH VOLTAGE AND LOW VOLTAGE DISTRIBUTION SYSTEM OVERVIEW



My testimony will address the current health of the HVD lines system, HVD substations, LVD substations, the Metro system, and System Protection Relays, and explain needed investments in those systems to address asset health; improve system performance; and improve reliability for customers, particularly by mitigating the risk of large customer interruptions. These investments will ensure both the reliability and cost efficiency of the distribution system by proactively addressing, repairing, and replacing assets before they fail and ensuring a reliable and resilient system that can serve electric peak demand. This testimony and associated exhibits outline how projected investments in those systems deliver on the Company's 2023 Electric Distribution Infrastructure Investment Plan ("Reliability Roadmap," formerly known as the "2023 EDIIP"), an amended version of which is included in this case as Exhibit A-129 (MPK-19). The capital investments outlined in this testimony are described in detail by sub-program and investment category, with discussion on the purpose of the program and the basis for the investment. Specific investments identified in the Reliability Roadmap include:

- Mitigating the risks from obsolete pole tops and deteriorated poles through investment in **HVD lines**;
- Mitigating the risks from deterioration through securing, inspecting, and upgrading **HVD and LVD Substations**;
- Mitigating the risks from deterioration through inspecting and upgrading the civil and electrical components of the Company's **Metro** assets;
- Enhancing and modernizing the protective system with **System Protection Relays**, and
- Ensuring the HVD System can serve electric peak demand, new interconnections, and support economic development through **HVD Load Growth & Interconnections**.

Please note that throughout my testimony I will often refer to the HVD lines system and HVD substations collectively as the "HVD system."

Q. Please provide an overview of the HVD system.

A. Consumers Energy's HVD system consists of HVD lines and substations that distribute electricity to its LVD substations. Information about the size of the system is shown below based on HVD line miles and number of substations. Additionally, the HVD system includes a system of protective relays, which I discuss separately in the section of my direct testimony on the System Protection sub-program.

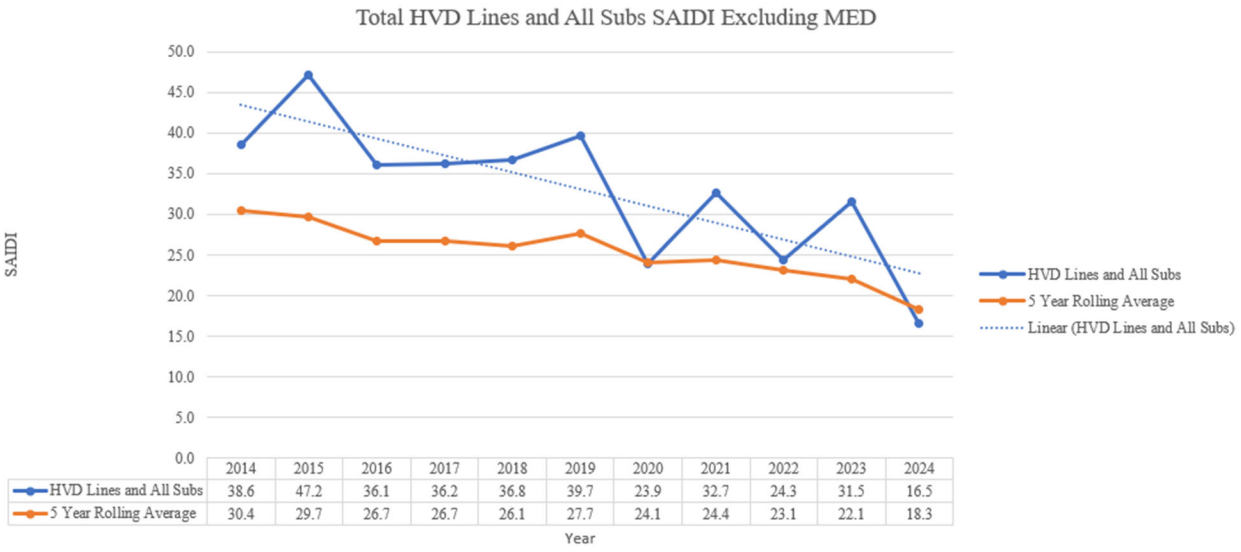
HVD Lines System:		HVD & LVD Substations:	
4600 Overhead Miles	4400 Miles of 46kV	**1138 Total Substations**	144 HVD Subs
	200 Miles of 138kV and 69kV		164 Strategic Electric Customer ("SEC") Subs
23 Underground Miles	19 Miles of 46kV		830 LVD Subs
	4 Miles of 138kV		

Q. Why must the Company make investments in the HVD system?

A. HVD lines and HVD substations are the backbone of the Company's distribution system, which means outages on the HVD system can lead to widespread interruptions for thousands of customers from a single incident. To mitigate against this risk, the Company must invest in the HVD system to ensure that the backbone remains resilient, able to quickly restore customers if outages occur, and to minimize the occurrence of outages in the first place. The Company has generally been successful at this over the years, meaning HVD assets do not usually contribute a major share of the Company's total System Average Interruption Duration Index ("SAIDI"). Indeed, historical investment levels in the HVD system have driven an improving trend line of overall HVD system performance in recent years.

Figure 2 below illustrates a gradual reduction in SAIDI. However, the risk of large HVD outages with a correspondingly high impact on SAIDI is always present if HVD assets begin to deteriorate. On average, when excluding major event days ("MEDs"), a single outage at an HVD substation or on a HVD line is 50 times more impactful than an LVD line outage, both in terms of SAIDI and number of customers impacted. Without proper attention to the HVD system, SAIDI impacts will quickly increase, to the detriment of customers. A reliable and resilient system backbone is required to continue the Company's downward and improving trend in SAIDI performance.

FIGURE 2



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
HVD Lines and All Subs	38.6	47.2	36.1	36.2	36.8	39.7	23.9	32.7	24.3	31.5	16.5
5 Year Rolling Average	30.4	29.7	26.7	26.7	26.1	27.7	24.1	24.4	23.1	22.1	18.3

Unfortunately, the asset health of many major components within the HVD system is deteriorating, with many of these assets well beyond their intended lifecycle. To ensure that this backbone infrastructure remains reliable and resilient, the Company monitors and assesses the asset health of HVD system components, so that areas of risk can be addressed proactively through investments. Increased investment in the HVD system, at the levels identified in the Company's Reliability Roadmap, is necessary to sufficiently reduce asset

risk on the HVD system, ensure a resilient backbone, and to contribute to further reduced SAIDI.

Finally, failed assets can present safety risk to the public and to Company employees, particularly when they create situations where people can be exposed to high-voltage energized equipment. Investments to address asset health concerns therefore mitigate public safety risks.

Q. Can you further elaborate on how HVD lines and substation investments align with the Reliability Roadmap?

A. As Company witness Kelly explains, the Reliability Roadmap includes increased investment in various areas, including the HVD system, necessary to reduce asset health risk to acceptable levels and reduce the risk of future outages. The investments identified throughout my testimony are aligned with those spending levels defined in the Reliability Roadmap, designed to ensure that the HVD system continues to provide a reliable and resilient backbone infrastructure, critical to supplying the LVD system. These investments will also help continue the downward trend in HVD SAIDI that the Company has seen in recent years, as shown in Figure 2 above.

Q. What is the Company's approach for investing in the HVD system?

A. The Company monitors the health of its HVD assets through a variety of data points from various maintenance and inspection programs. Through these processes, the Company determines the asset health risk for HVD assets, which informs investment decisions in HVD capital projects. These capital investments proactively address risk on HVD assets through repair, replacement, or upgrade prior to asset failure. A significant proportion of the Company's HVD investments are directed toward identified asset health issues and

issues identified during inspections; this is the basis for the Company's investment in its HVD reliability programs. All of these investments are intended to ensure the continued reliable and resilient operation of the HVD system. It is important to note that HVD system improvements may not always be captured in reduced SAIDI from existing levels, but there are still substantial customer outage minutes to avoid by preventing future failures from occurring.

When needed, the Company also expands and/or modernizes the grid to serve growing loads from commercial and industrial ("C&I") customer base as they electrify their businesses. All HVD capital investments are identified and planned to support the overall objectives and strategy outlined in the Company's Reliability Roadmap.

Q. Why must the Company invest in LVD substations?

A. As with HVD system assets, LVD substations play a crucial backbone role in the distribution system, since they directly feed the LVD circuits that serve customers. While HVD substations often serve many downstream communities, LVD substations often serve a single community or a more focused local area, but this means that a given LVD substation can have a major impact on that single community. Outages on LVD substations lead to significant interruptions for customers when they happen, and as I discuss in my direct testimony many of the Company's LVD substations have asset health risks that must be addressed to prevent those outages.

Q. Why must the Company invest in the Metro system?

A. The Metro system is dedicated to providing underground electric service in six key downtown areas in the Company's service territory and is critical for the economic health and development of the cities that it serves. As with HVD lines and with substations, the

Company must ensure that the Metro system provides the needed electrical backbone for these downtown areas and must invest accordingly in order to support the asset health of the Metro system.

Q. How are the HVD lines, substations, and Metro system capital investments summarized in this proceeding?

A. The historical year is calendar year 2024. The bridge period consists of the 16 months beginning January 1, 2025, and ending on April 30, 2026. The test year is the 12 months beginning May 1, 2026, and ending on April 30, 2027.

Q. Please summarize the HVD lines, substations, and Metro system capital expenditure plan in this filing by historical year, bridge period, and test year.

A. The HVD lines, substations, and Metro system capital expenditures described in my testimony are summarized in Figure 3 below. Throughout my direct testimony, I will explain how these proposed investment levels will deliver meaningful benefits for customers through specific projects on the system.

FIGURE 3
HVD/SUBSTATIONS/METRO CAPITAL EXPENDITURE SUMMARY

	Bridge Period	Test Year
All Programs	$542,846,000	$417,546,000

Q. What specific HVD system, LVD substation, and Metro projects does the Company expect to invest in during the bridge period and test year?

A. Specific projects are identified in Exhibits A-109 (MLH-3) and A-110 (MLH-4). The exhibits include projects identified with scope, cost, location, benefit type, and benefits. The two quantitative benefit types are:

- Customer outage minutes avoided: Product of the number of customers that experience an extended outage of electrical service and the duration of outage measured in minutes.

- Customers impacted: Number of customers served by a project. In the case of commercial customers, the customers impacted are treated as "1."

Note that not all projects have quantitative benefits. Some projects may be completed for regulatory compliance, based on the Company's obligation to serve customers, or other reasons. Company witness Kelly provides more details about how the quantitative benefits are calculated. Throughout my direct testimony, I will explain more about the specific benefits of each investment sub-program.

II. HVD SYSTEM STRATEGY

Q. What challenges are faced by the HVD system?

A. The HVD systems are considered the backbone infrastructure of the electric distribution system because they connect the electric transmission system to the Company's LVD system. When outages occur on the HVD system, this backbone characteristic means interruptions to customers can be widespread and long in duration. To mitigate this, the HVD system needs to be resilient, which is why it is largely a looped system with built-in redundancies capable of either continuing service to customers or at least minimizing the number of impacted customers due to the failure of any single component. To maintain redundancy and ensure that this backbone infrastructure remains strong, the Company monitors and assesses the asset health of HVD system components, so areas of risk can be addressed proactively. This practice is discussed in detail in the Reliability Roadmap.

Historical investment levels in the HVD system have improved the trend of overall HVD system performance as illustrated in Figure 2. However, significant variation in SAIDI contribution can also be seen from one year to the next, highlighting the significance

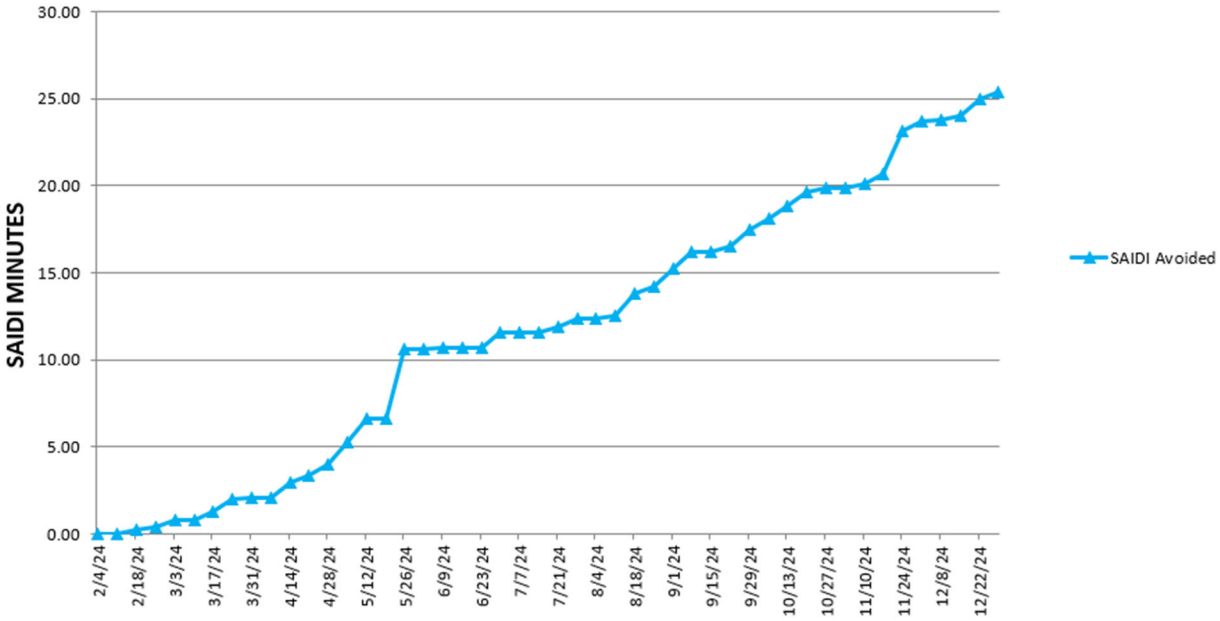
of HVD system outages that do occur. The Company continues to face deteriorating asset health year-over-year for many of its HVD assets, which threaten their ability to continue to perform as a reliable and resilient backbone for the entire system.

Q. How is the Company able to substantiate that its HVD assets face declining asset health?

A. This is clearly supported by the annual findings from the Company's annual inspections, maintenance, and diagnostic test of HVD assets that a) identify anomalies that must be addressed prior to failure; and b) provide key insights into asset health and how assets are performing. In 2024, the Company's inspections identified anomalies that, if not addressed, would have resulted in 25.3 SAIDI minutes, as shown in Figure 4 below. This is also discussed in more detail later in my direct testimony when discussing the HVD Lines and Substations Demand Failures sub-program. In this figure, each data point reflects one week of activity. During each week, the Company mitigates any defects identified during inspections that would fail within months and cause interruptions to customers if not addressed (anomalies are typically addressed within one to two weeks of identification). The Company then calculates the SAIDI minutes that would result if the affected asset failed and caused interruptions to customers. The blue trend line indicates the cumulative avoided SAIDI throughout the year.

FIGURE 4

SAIDI avoided through correction of defects



For comparison, the equivalent avoided SAIDI from correcting anomalies was 16.8 minutes in 2023, indicating a worsening trend in HVD asset health, as the Company is finding more high-priority anomalies year-over-year. Historically, the equivalent amount was only about 10 avoided SAIDI minutes per year. This is one demonstration that HVD asset health is worsening, as the Company, through better use of technology and inspection techniques, is finding increasing levels of these narrowly avoided failures. Without increased proactive investment, anomalies will increase to a level where the Company cannot proactively mitigate failures, and significant interruptions to customers will result.

Q. How do inspections, maintenance, and diagnostic testing provide further insights into asset performance and health beyond these avoided interruptions to customers?

A. These key data points are collected and reviewed to build an asset health model that is used as a tool in determining capital investments and maintenance plans and establishing a general trend of asset health. The Company uses this asset health model to evaluate the

assets on its system and identify all assets that face declining asset health, using a variety of data points to assess risk levels. The asset health model considers multiple inputs like asset type, manufacturer, condition, age, actual outages, and level of degradation collected about the asset during inspections, maintenance, and/or annual diagnostic testing to provide a holistic view of the asset's health. By applying this asset health model process to its HVD assets, the Company can document which assets face declining health and design projects to fix these issues; projects proposed in the instant case, particularly in the Reliability sub-programs, have been identified in this way.

Note that while age is an input in the asset health model, it is not a sole determining factor used to initiate a project for replacement or retirement. For example, age is an important factor in evaluating substation transformer banks that are over 50 years old, as age directly impacts how internal components break down. Identifying transformers over 50 years of age helps the Company prioritize replacements among multiple transformers of differing ages when they otherwise have the same overall health as determined by inspections and diagnostic testing. In other words, when multiple transformer banks have the same health score from inspections and tests, the Company will replace both transformers, but the transformer over 50 years of age will be conducted before the one that is 30 years old.

It is important to note that the asset health model is meant to identify assets with elevated risk levels, but it is not meant to predict specific future failures and identify a date and time when they will definitely fail. The asset health model gives indications of where

problems will likely occur so the Company can begin planning ahead and know where to focus its attention to address the biggest risks on the system.

Q. Please describe how the asset health model works in more detail.

A. As stated above, the purpose of the asset health model is to identify where the Company has elevated asset health risk so the Company can plan ahead to address issues. Planning ahead is essential because many projects have long lead times, and planning must begin multiple years in advance; for many projects, the Company must first obtain rights of way and order long lead time materials well before design or construction can begin.

For HVD, the asset health model includes lines and substations and their components, as well as the relaying assets that are the subject of the System Protection sub-program discussed later in my testimony. For each type of asset, the asset health model incorporates critical asset factors such as inspection results and testing results, plus known manufacturing issues that affect certain types of equipment. In the case of substation transformers and breakers, asset age is also one of the factors included in assessing risk; because these assets have a known correlation between age and failure, the Company would replace a 50-year-old transformer before a 30-year-old transformer, all else being equal.

For each asset on the system, these inputs are used to generate an asset health score. An HVD line's asset health score combines multiple data points that include if it is a radial line or not, potential customer impact, type of conductor, configuration, number of trips, number of lockouts, red tagged poles, and victor insulators. Figure 5 below shows the point value assigned to each factor of a line segment that helps generate its overall health score, and Figure 6 shows a sample calculation of a line segment health score.

FIGURE 5
HVD LINE ASSET HEALTH WEIGHTING

Radial line	Points per mile	5
Customers	Points per 1,000	2
Obsolete conductor	Points per mile	5
Unshielded conductor	Points per mile	1
Top 25 contingency	Yes	0
Trip	Points per trip	1
Lockout	Points per lockout	2
Rush red tagged pole	Points per pole	2
Planned red tagged pole	Points per pole	1
Victor insulators	Point per insulator	0.3

FIGURE 6
HVD SAMPLE HEALTH SCORE BY LINE SEGMENT

Line Name	Total Point	Radial	Customer Impact	Obsolete Conductor	Unshielded	Victor Insulators	Red Tagged Poles	Lockout
Line Segment A	133	30	6	0	0	60	25	12
Line Segment B	100	0	10	50	10	0	30	0
Line Segment C	86.6	25	5	0	0	3.6	45	8

An HVD substation's asset health score combines the scores of multiple components within the substation. Figure 7 below shows an example of an asset health score for a substation, showing how multiple component scores total the station score. Figure 8 shows how transformer factors impact the total score for the transformer.

FIGURE 7
HVD SAMPLE HEALTH SCORES FOR SUBSTATIONS

Category	Points per Occurance	Sub A	Sub B	Sub C
AC/FP/REC Wound	25	0	0	0
Age 50+	20	1	1	1
Oil or N2 Leaks	10	1	1	0
Transformer Internal Infrared	10	0	1	0
DGA Score	20	1	0	0
Brand A Bushing Issue	15	1	0	0
Brand B Bushing issue	5	0	0	0
IR P1/P2	20	0	1	0
Doble or Elec Test Issues	15	0	1	0
Transformer & Bushings Total		65	75	20
REG/LTC TOA R3/4	25	1		
IR P1/P2	20			
REG/LTC Total		25	0	0
OCB > 50 Yrs; GCB > 25 Yrs	5	7	3	1
3PH Reg/LTC Demand Order	10	1		
BRKR Oil or SF6 Gas Quality/Leaker	15		1	1
IR P1/P2	15			
Maint/RP Priority List	10			
Oil and Gas Circuit Breakers Total		45	30	20
99 & Cap Bank CSWs/VSW Issues	15	1		
SPT Watch List	10	2	1	1
Str & Concrete	5	1		
Other	5			
IR P1/P2	15		1	1
Ops Limiting Equip	20	1		
Station & Other Totals		60	25	25
Total Score Normalized		100	66.66667	33.33333
Gross Total		195	130	65

FIGURE 8
TRANSFORMER ASSET HEALTH WEIGHTING

Factor	% of Total Score
Age over 50+ years	14%
How the Transformer is Wound	18%
Nitrogen Gas or Oil Leaks	7%
Allis Chalmers Infrared	7%
Dissolved Gas Analysis	14%
Bushing Type	4-14%
Electric Testing Results	11%

Q. How are asset health scores used by the Company once generated?

A. In general, the Company uses asset health scores to rank lines and substations for the prioritization and development of projects. Since assets with higher scores are at greater risk of deterioration and failure, they are prioritized for projects to fix identified reliability issues. Asset health scores indicate not only *that* an asset faces deteriorating health, but also *what* is driving the issue, and this helps determine what kind of project is appropriate. For example, an HVD line may have a high score simply due to the presence of some deteriorating poles, so the Company would respond to that by replacing those poles. If the line had a score indicative of various other equipment issues, then a full line rebuild may be more appropriate.

However, the Company does not necessarily strictly "go down the list" in prioritizing and scheduling HVD projects. Many large HVD projects have multi-year schedules, with a series of steps that must be completed in order, and this affects when projects can be executed. For example, the substation with the highest asset score today may require a full rebuild. Rebuilding that substation may require the Company to acquire new real estate first and procure long lead time materials before construction can take place, meaning construction may not be possible for a few years. In the meantime, the substation with the fifth-highest asset score today may be fixable through a quicker project that can be

done this year. In this situation, the Company would be completing a technically lower-ranked project before a higher ranked one, due to timing issues. Additionally, the multi-year nature of some projects means that a future project may move up or down in prioritization while it is in development as information about other asset health needs come to light. This is one reason why an asset health model is useful in the first place: the Company can optimize asset health to reflect shifting needs.

Furthermore, the Company often tries to coordinate projects to create efficiencies, so projects may be moderately reprioritized to take advantage of keeping a workforce in a specific area, or to coordinate with other kinds of infrastructure work being done by state and local governments.

Q. If the Company does not invest in the HVD system at the levels proposed in the instant case, what risks will this create for the Company's system?

A. As noted earlier in my direct testimony, a single outage at an HVD or LVD substation or on an HVD line is 50 times more impactful than an LVD line outage, both in terms of SAIDI and of customers impacted. The Company has documented an increase in the number of anomalies found on the HVD system, and the Company's asset health modeling gives the Company detailed insight into which assets need investment most urgently. If the Company does not make the needed investments in the HVD system, more assets will simply be run to failure, and HVD SAIDI would degrade; again, note that in 2024 the Company had HVD assets that were within months of failures that would have increased SAIDI by over 25 minutes. Throughout my direct testimony in the respective sub-program sections, and in my exhibits, I will explain how specific investments will deliver clear reliability benefits to customers, particularly through future customer outage minutes avoided through the

investments. In the aggregate, planned investments will not only *prevent* future large-scale interruptions to customers, but they will also *reduce* SAIDI on a net basis.

Q. How has the Company determined that a single HVD outage is similar in impact to 50 LVD outages?

A. In 2024, the average LVD outage on the Company's system impacted 38 customers and contributed 0.003 minutes of SAIDI, while HVD lines and substation outages on the Company's system, on average, impacted 1,863 customers and contributed 0.18 minutes of SAIDI. This data highlights the impact that each HVD line and substation outage has on the system; while they have fewer total outages events, the outages that do occur are much more impactful than outages on the LVD distribution system.

Q. What role does the Company's inspections play in this process of identifying HVD investment needs?

A. As stated above, inspections provide critical inputs into the asset health model, helping the Company identify HVD investment needs in the medium to long term. Inspections are also crucial for identifying already failed components (which are then fixed in the HVD Lines and Substations Demand Failures sub-program) and in identifying components that present a near-term risk of failure (which are typically then addressed in the HVD Lines Reliability or HVD Substations Reliability sub-programs). In these situations, the Company develops a project to address the problem immediately or in the very short term; this kind of work does not go through the asset health model because there is no need to assess longer term risk when the asset has already failed or is about to fail.

Q. Does the Company make any investments in the HVD system that are not directly related to asset health or reliability?

A. Several HVD investment sub-programs address other important concerns. The HVD system plays a critical role in supplying electricity to large C&I customers that play an essential role in Michigan's economy. As Michigan attracts new large C&I customers, their demand for electricity will require expansion of the HVD system in certain areas, an issue that was discussed in the Reliability Roadmap. These needs are most specifically addressed in the Company's HVD Strategic Customers New Business and Metro New Business sub-programs, discussed later in my testimony. Issues related to load growth are also addressed in the HVD Lines and Substations Capacity sub-program and the LVD Substations Capacity sub-program, and the HVD Lines and Substations Capacity sub-program also addresses other important needs related to the functioning of the grid, such as interconnections with the transmission system.

Finally, the Demand Failures and Asset Relocations sub-programs addressed later in my direct testimony deal with emergent issues on the system that may not always be related to asset health.

III. LVD SUBSTATIONS STRATEGY

Q. Please provide an overview of the Company's LVD substations.

A. The Company has approximately 830 LVD substations in its system to step down voltage from the HVD lines system to the LVD lines system. LVD substations are supported by the Company's fleet of mobile substations, which provide continuity of electric service to customers during planned and unplanned LVD substation outages where redundancy is not present or load transfers to adjacent substations are not available.

Q. What challenges are faced by the Company's LVD substations?

A. As with the HVD substations, the Company's LVD substations face similar asset health risks that the Company must address in order to maintain continued reliability for customers, especially because LVD substations do not always have the same levels of redundancy as HVD substations. As with the HVD substations, LVD substations have their own asset health models to inform investments, which I will address in more detail in the section of my direct testimony covering the LVD Substations Reliability sub-program. LVD substations face some unique challenges that are addressed through corresponding investment categories that I will discuss in my direct testimony, such as animal intrusions and the use of obsolete Allis Chalmers transformers, which both drive investments in LVD substations.

Additionally, the locations of LVD substations on the system – often in communities relatively close to load – means that LVD substations are particularly susceptible to the impacts of localized load growth, which drives the need for investments in LVD Substations Capacity.

IV. METRO SYSTEM STRATEGY

Q. Please provide an overview of the Metro system.

A. The Metro system provides underground distribution service in the downtown areas of six cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw. Much of the Metro infrastructure was first installed in the 1910s through the 1950s to accommodate electric distribution in already busy downtown areas. Metro infrastructure is used, both in the past and today, to manage the density of downtown city centers, facilitate electrical repairs, and for aesthetics.

The primary benefit of the Metro System is to address space limitations where numerous utilities (electric, gas, telecommunications, water, and sewer) must use limited right-of-way ("ROW") in public streets and alleys, especially because high-rise buildings have greater utility needs than in lower density areas. The Company's Metro planning group focuses solely on these key downtown areas, reflecting the Company's commitment to investment in Michigan by dedicating specific attention to these areas of economic growth.

Q. What challenges are faced by the Metro system?

A. As with the HVD system and LVD substations, the Metro system also faces asset health risks that the Company must address to ensure continued electric reliability for customers in those six downtown areas. The Metro system has its own asset health model, which I will discuss in more detail when addressing the Metro Reliability sub-program later in my direct testimony. The Metro system does not face as many asset health challenges as other parts of the system, and Metro Reliability investment is remaining relatively flat.

On the other hand, new economic development projects in some of the downtown areas are necessitating increased investment in the Metro New Business and Metro Asset Relocations sub-programs, which I will discuss later in my direct testimony.

V. CAPITAL SPENDING PROGRAMS

Q. How does the Company classify its HVD capital investments?

A. As explained by Company witness Kelly, the Company makes capital investments under two broad classifications, *planned* and *unplanned*. Each of these classifications include capital programs addressed in my direct testimony, as outlined in Figure 9 below. Each classification corresponds to one or more capital programs, which are in turn divided into constituent sub-programs and investment categories.

FIGURE 9
PROGRAM CLASSIFICATION DESCRIPTIONS & HVD SUB-PROGRAMS

Classification	Description	HVD Programs included
Planned	Investments planned to proactively improve grid reliability through capacity upgrades and investments in new tools and technology	Reliability, Capacity, "Electric Other"
Unplanned	Demand-driven and customer-driven needs	New Business, Demand Failures, Asset Relocation

Q. Please summarize the HVD capital expenditure plan in this filing.

A. In this filing, the Company is projecting to spend $417,546,000 in capital projects on the HVD system, substations, and the Metro system in the test year, and $542,846,000 in the bridge period. This investment plan is summarized by capital program in Figure 10 below. Increases in the various program areas are covered in their respective sections later in my testimony detailing the need to increase funding and how customers benefit from the projected level of spending.

FIGURE 10
HVD/SUBSTATIONS/METRO CAPITAL EXPENDITURES AND BENEFITS BY PROGRAM ($000S)

Work Type	HVD Program Area	2024 Actuals	Bridge Period	Test Year
Planned	Reliability	$ 110,315	$ 337,137	$ 273,161
	Capacity	$ 53,050	$ 70,569	$ 51,699
	Electric Other	$ 896	$ 447	$ 294
Unplanned	New Business	$ 69,024	$ 96,498	$ 51,777
	Demand Failures	$ 23,201	$ 20,882	$ 19,311
	Asset Relocation	$ 12,265	$ 17,291	$ 21,304
Total		**$ 268,751**	**$ 542,824**	**$ 417,546**
Benefits				
Projected Total Customer Minutes Saved			**90,111,949**	**77,608,571**

Q. What capital projects does the Company expect to invest in during the bridge period and test year?

A. A comprehensive list of currently identified Company HVD projects and associated expenditures for the bridge period is provided in Exhibit A-109 (MLH-3), and a list of currently identified projects and associated expenditures for the test year is provided in Exhibit A-110 (MLH-4). Detailed discussion on each capital program and sub-program is provided in the respective sections of my direct testimony.

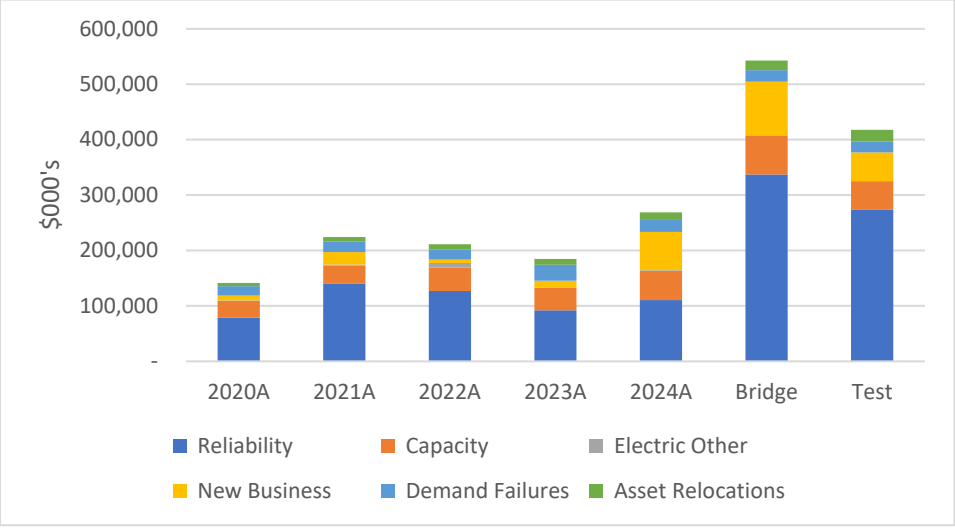
Q. Are contingency expenses included in any of the projected capital expenditures included in your testimony?

A. No. Contingencies are not included in the projected capital expenditures.

Q. How does the HVD capital expenditure plan in this filing compare to historical investments?

A. An overview of historical HVD capital expenditures by program from 2019 through 2024 and projected HVD expenditures for the bridge period and test year are shown in Figure 11 below.

FIGURE 11
HVD INVESTMENT BY PROGRAM



Q. Why are investment levels higher in the bridge period and test year compared to recent historical levels?

A. As discussed above, the Company has increased its investment levels to align with the levels established in the Reliability Roadmap to be able to deliver on its reliability goals. To ensure reliability and resiliency, the Company must focus on hardening and improving the performance of assets in poor health on the HVD system like poles, wire, breakers, and transformers. This reliability spending allows the Company to address asset health risk proactively and keep assets within their intended useful lifecycle. The goal with reliability is simple: fewer and shorter outages for customers. Additionally, the Company has increased investment relative to historical levels in the HVD Strategic Customers New Business sub-program in order to meet the needs of new and expanding C&I customers, an issue discussed in the Reliability Roadmap. Finally, it is important to note that the bridge period is 16 months long, so total spending is higher in absolute terms than in the other 12-month periods shown in the chart.

Q. Are there any general principles that govern how HVD assets are identified so the Company can develop targeted projects for those assets?

A. In general, projects are identified using data inputs in the asset health model, as discussed earlier in my direct testimony. The Company performs quarterly operating reviews ("QORs") of the asset health of components on the system based on information gathered through its many inspections and maintenance activities. Gathered data informs the Company on an asset's health based on likelihood, consequence, and severity of an asset's failure, also known as that asset's risk. When assets are identified as being at-risk, the Company develops projects to address that risk proactively. The QOR lets the Company

monitor shifts in asset risk and ensures continued investment in the correct places based on the latest asset information.

Q. When the Company identifies assets that are at risk and require investment, how does the Company identify and validate that HVD capital investments are reasonable and prudent for customers?

A. For many projects, the Company considers its proposed electric distribution investment against alternatives and develops a "concept approval" to test and demonstrate why the selected project is reasonable and prudent, as discussed in more detail in the direct testimony of Company witness Kelly. As he discussed, Company projects are generally selected using the "least-cost, best-fit" principle. Through this vetting and concept approval process, the Company ensures that it has a strong and robust justification for electric distribution projects that are selected for implementation. The general structure of a concept approval includes the following:

1. Identification of the system risk;
2. Identification of alternatives to address the system risk;
3. Determination of costs and benefits of the alternatives;
4. Selection of best alternative;
5. Approvals; and
6. Revisions, where necessary.

Q. How do customers benefit from the concept approval process?

A. The concept approval process provides a rigorous approach and governance structure to identifying HVD system problems and needs, alternative solutions, and recommended

alternatives. It provides for peer review and management oversight to ensure that the Company's investment plans are well justified, reasonable, and prudent for customers.

Q. How are these projects justified as reasonable and prudent investments for the customer?

A. As mentioned above, an asset's health is identified through the Company's various health models which leads to the development of a concept to address any asset health concern. This process ensures that the Company continues to prioritize work based on the assets that are in poor health and represent the greatest risk to system performance. Conversely assets near failure as identified during regular inspection of the HVD system that need to be addressed in a timely manner to prevent customers from experiencing an outage do not follow the concept approval process because there are only two options: replace the asset prior to failure or replace it after it fails which causes an outage to customers. As discussed in the HVD system overview, running assets to failure without doing proactive work would result in a significant increase to HVD system SAIDI. The increase in proactive spending allows the Company to address system health and degradation before customers experience outages. These system defects are prioritized according to their risk to system operations and customer reliability and executed to the greatest efficiency to prevent an actual failure.

VI. HVD SUB-PROGRAM SPENDING DETAILS

A. Planned Spending Programs

1. Reliability

Q. Please describe the Reliability sub-programs.

A. The overall purpose of the Reliability Program is to ensure the long-term safe and reliable operation of the distribution system, as described by Company witness Kelly. In my testimony, I will address eight HVD Reliability sub-programs:

- HVD Lines Reliability
- HVD Substations Reliability
- Transformer Bank Replacements and Substation Rebuilds
- LVD Substations Reliability
- LVD Substations Rehabilitation
- Metro Reliability
- Metro Rehabilitation
- System Protection

a) HVD Lines Reliability

Q. Please explain what projects, activities, and other types of work are accomplished by expenditures in the HVD Lines Reliability sub-program.

A. HVD Lines Reliability investments are intended to address deteriorated HVD line assets that have been assessed to be in poor health, mitigating and reducing the contribution of the Company's HVD lines to SAIDI and improving their resiliency. Work in the HVD Lines Reliability sub-program consists of seven investment categories:

- HVD line rebuilds

- Pole top rehabilitation miles
- Individual pole top replacements
- Pole replacements
- Switch replacement projects, including supervisory control and data acquisition ("SCADA") additions
- Line sensor deployments
- ROW Acquisition for HVD line rebuilds

Each project in this sub-program is customized to address the particular issues on individual poorly performing assets and deteriorated lines, based on an asset's, or collection of assets', risk to system performance. Line sensors and ROW acquisition were new investment categories in this sub-program in Case No. U-21585 in 2024. Line sensors were historically in the HVD Lines and Substations Capacity sub-program but were transferred because their main function is to improve the reliability monitoring of the system and assist with quick identification of faulted line segments. ROW acquisition for reliability projects was also historically in the HVD Lines and Substations Capacity sub-program, but was transferred in order to better align the costs of line rebuilds with the actual work.

Q. Has the scope of the HVD Lines Reliability sub-program changed since Case No. U-21585 was filed?

A. Yes. In Case No. U-21585 and prior cases, the Company had a sub-program called HVD Lines and Substations Rehabilitation, which included various types of investments focusing on line and substation assets that were assessed to be at risk of imminent failure. Work related to HVD lines that had been in that former sub-program has been transferred to HVD Lines Reliability in the instant case, so that all investments addressing the reliability of HVD lines is now within one sub-program.

Other work that was formerly included in the HVD Lines and Substations Rehabilitation sub-program was transferred to the HVD Substations Reliability sub-program, as discussed later in my direct testimony. The remaining work that was formerly included in the HVD Lines and Substations Rehabilitation sub-program is now included in the Transformer Bank Replacements and Substation Rebuilds sub-program, as also discussed later in my direct testimony.

Q. How has this transfer of work from one sub-program to another affected the investment categories in the HVD Lines Reliability sub-program?

A. The pole replacement and switch replacement investment categories in the HVD Lines Reliability sub-program now have a larger volume of work in them, because they now include work that was previously done in the former HVD Lines and Substations Rehabilitation sub-program. The individual pole top replacements investment category is new to this sub-program in the instant case, having been formerly included in the HVD Lines and Substations Rehabilitation investment category. The other investment categories in the HVD Lines Reliability sub-program are unchanged. This is illustrated in Figure 12 below.

FIGURE 12
CHANGES TO HVD LINES RELIABILITY INVESTMENT CATEGORIES SINCE CASE NO. U-21585

Investment Category	Change since Case No. U-21585
HVD Line Rebuilds	No Change
Pole Top Rehabilitation Miles	No Change
Individual Pole Top Rehabilitations	New to HVD Lines Reliability; formerly in HVD Lines and Substations Rehabilitation
Pole Replacements	Includes preexisting work in HVD Lines Reliability and work formerly in HVD Lines and Substations Rehabilitation
Switch Replacements	Includes preexisting work in HVD Lines Reliability and work formerly in HVD Lines and Substations Rehabilitation
Line Sensors	No Change
ROW Acquisition	No Change

Q. How does the HVD Lines Reliability sub-program deliver on the intent of the Reliability Roadmap?

A. As discussed in the Reliability Roadmap, the Company's primary strategy for HVD lines is to address HVD line components – poles, pole tops, conductors, and switches – with poor asset health through a workplan that replaces those assets that have been identified as having poor health. The Company focuses on lines with consistently poor reliability performance and looks for the best remediation strategy to reduce risk and prevent future outages in the most effective and economical way, generally using a least-cost, best-fit approach.

As described in the Reliability Roadmap, this sub-program specifically addresses risks in the four major components of the HVD lines system: conductors, insulators, poles, and switches. The Company identifies and assesses the health and risks related to these four major components and mitigates that risk using a combination of line rebuilds, pole top rehabilitation, switch and pole replacements to reduce the population of each asset at risk and improve reliability performance. The HVD Lines Reliability sub-program is aligned

with the Reliability Roadmap because it executes the projects listed in Exhibit A-109 (MLH-3) and Exhibit A-110 (MLH-4) for specific HVD line rebuilds, pole top rehabilitation projects, switch replacements and individual pole replacements needed to continue to address the asset health risks on conductors, insulators, poles, and switches identified in the Reliability Roadmap.

While the Reliability Roadmap primarily connects these HVD lines investments to reducing asset health risk, these investments also play a key role in SAIDI performance, as discussed by Company witness Kelly.

HVD Line Rebuilds and Pole Top Rehabilitations Miles

Q. What kind of work is done in the HVD line rebuilds and pole top rehabilitation miles investment categories?

A. HVD line rebuilds consist of a complete overhead rebuild of a line or line segment, including insulator, conductor, cross-arm, and pole replacements. Pole top rehabilitation miles consist of replacing deteriorated cross-arms, insulators, cross-arm braces, and hardware on pole tops without replacing the poles themselves, again along an entire line or line segment. Lines in poor asset health that currently meet modern construction and design standards, and that have standard conductors, will primarily receive pole top rehabilitation, while lines in poor asset health that use non-standard and obsolete construction or equipment will typically be rebuilt.

HVD line rebuilds take conductor, poles, and insulators in poor asset health off the system as lines are rebuilt to current construction standards/configurations. Pole top rehabilitation projects directly address lines with poor insulator health which is the leading cause of line outage events over the past 5 years. See Company witness Kelly's testimony.

Q. How does the Company determine which HVD line sections should be addressed with line rebuild or rehabilitation projects in this sub-program, and how does it determine whether to rebuild the line or only do rehabilitation?

A. The Company utilizes past system performance and asset health data collected from inspection programs to identify and prioritize projects that will optimize system performance, reduce risk, and provide benefit to customers through improved reliability. This data builds a model to prioritize HVD line segments based on actual outage history, conductor type and configuration, health of insulators and poles, and the potential customer impact if the line segment were to fail.

With few exceptions, lines that use non-standard and obsolete construction or equipment are rebuilt to the modern standard with a new insulator, conductor, cross-arms, structure replacements, tree clearing, and ROW procurement as needed. Lines that use standard construction and conductor, have adequate pole health, but have poor insulator health, are candidates for pole top rehabilitation instead of a complete rebuild.

Q. Why does the Company rebuild lines that use non-standard and obsolete construction or equipment?

A. HVD lines with non-standard construction typically have higher outage rates due to their outdated construction standards, such as unshielded conductors (which are more vulnerable to lightning), small single-layer conductors, or copper conductors (both of which are less durable than standard construction and require non-standard components to repair them when they fail). Pole top rehabilitation does not mitigate these issues. Rebuilding a line to modern standards improves durability and operational flexibility.

It is critical to remember that line rebuild projects and pole top rehabilitation projects both address lines that have already been identified as having outage problems. The question is simply whether the best way to address those problems is through a rebuild or rehabilitation.

Q. Please further explain the impact of asset health risk on project selection.

A. As shown in Figures 13 and 14 below, a substantial percentage of the Company's HVD lines insulators are at risk, with 35% falling into the vintage and victor, concerned and high-risk categories. Lines with high population of these insulators are considered to be in poor asset health and are prioritized accordingly. Similarly, conductor assets are also at some risk, with 14.4% of conductors classified as high risk based on their condition. Proposed line rebuild projects directly address the 14.4% of at-risk conductors by bringing those lines into the green portion of the donut chart. A major purpose of the Company's projected increase in HVD Lines Reliability investments is to address these risks.

FIGURE 13
HVD LINE INSULATOR HEALTH

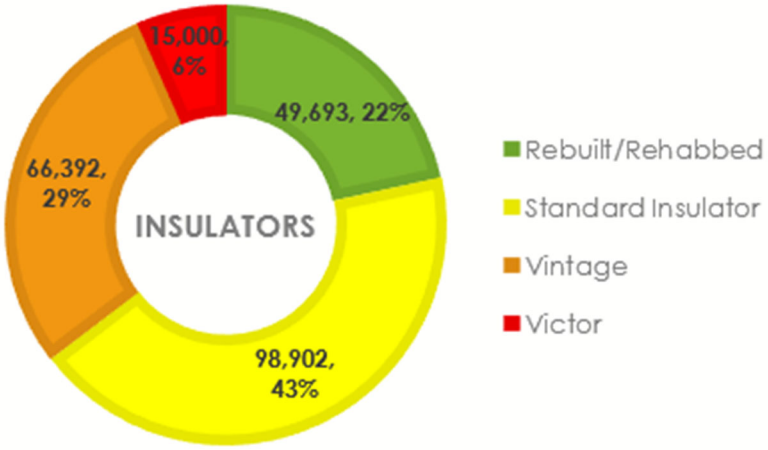
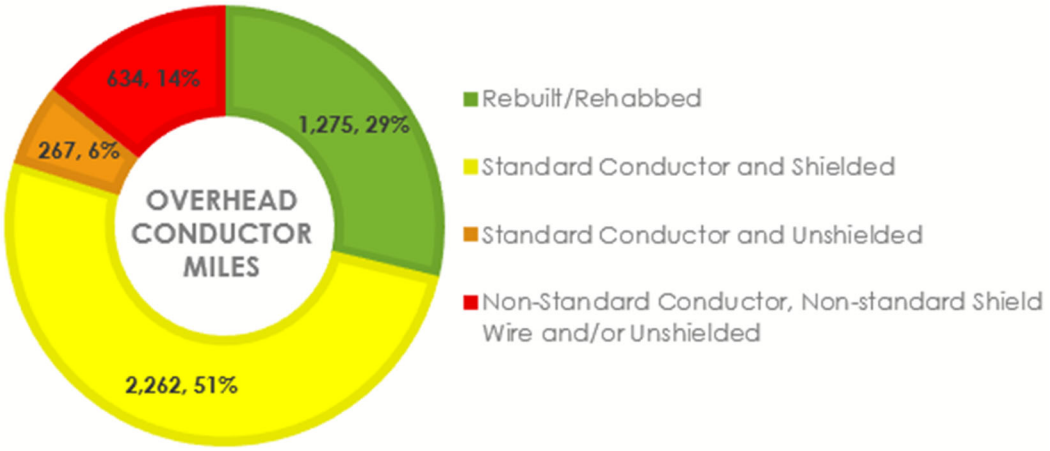


FIGURE 14
HVD LINE CONDUCTOR HEALTH

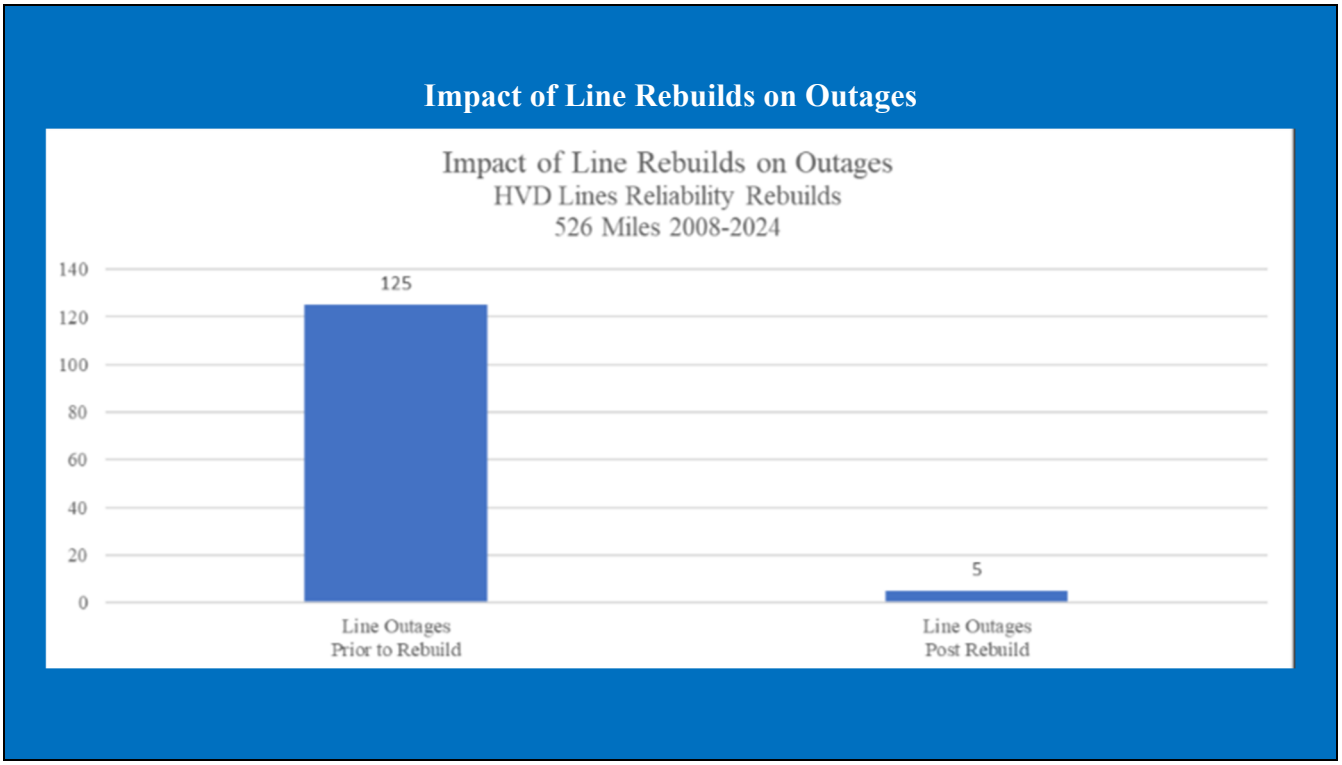


Q. What specific benefits have HVD line rebuilds delivered for customers?

A. Line rebuilds substantially improve the performance of a line, reducing or eliminating outages and correspondingly reducing or eliminating interruptions to customers caused by that line. Figure 10 below shows how, after completing a line rebuild, a line section typically experiences minimal line equipment-related outages with a demonstrated 96% reduction in outages.

In Figure 15, Prior Outages represent the number of line outages due to equipment failure within the line section specified in the order number that occurred during the five years before the rebuild Completion Date. Post Outages represent the number of line outages due to equipment failure that have occurred since the Completion Date within the rebuilt line section. Customers realize the benefit of fewer outages when the Company rebuilds an HVD line section.

FIGURE 15



Individual Pole Top Replacements

Q. What work is done in the individual pole top replacements investment category?

A. The individual pole top replacements investment category does similar work to the pole top rehabilitation miles investment category, but instead of addressing entire lines or line segments, the individual pole top replacements investment category only replaces individual pole tops that represent an imminent failure risk. As noted above, individual pole top replacements were formerly accounted for in the HVD Lines and Substations Rehabilitation sub-program.

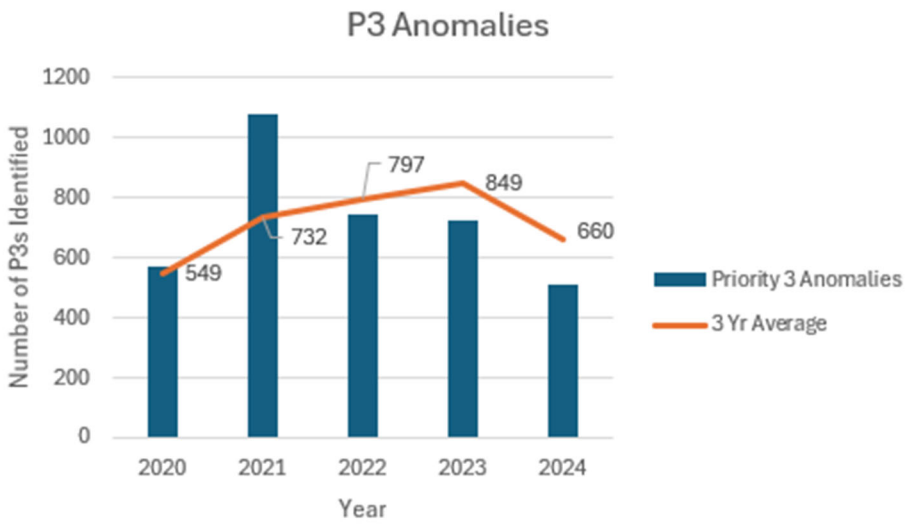
Q. How does the Company identify individual pole tops that are at imminent risk of failure?

A. Individual pole top replacements are identified almost exclusively by helicopter and ground inspections. Pole top replacements identified as Priority 1 and some Priority 2 anomalies

are replaced under the HVD Lines and Substations Demand Failures sub-program. The remaining Priority 3 anomalies represent imminent failure risk and fall into this sub-program.

During these inspections, the Company identifies anomalies visually using a camera that combines corona camera technology (for detecting cracked insulators using ultraviolet technology) with an infrared camera (to detect elevated thermal activity) during helicopter inspections to detect anomalies with high levels of accuracy. Although inspections have yielded fewer anomalies since 2021, as shown in Figure 16 below, the Company is still consistently identifying over 500 anomalies per year, with an average of almost 700 anomalies per year. This indicates that consistent investment in this category is needed to keep up with the deterioration of pole top assets such as cross arms and insulators. Failure to do so will result in worsening asset health risk on HVD lines, increased failures, and increased spending in the HVD Lines and Substations Demand Failures sub-program.

FIGURE 16



Q. Can you provide further discussion on the Company's helicopter and ground inspections?

A. The Company performs aerial inspections of its HVD lines system via helicopter. As this is a highly effective way to reduce HVD lines-related customer outages, the Company has adjusted its helicopter inspection program to ensure flights happen earlier in the year and more often to support the identification and correction of anomalies before they result in outages.

The results of the helicopter inspection program are a significant source of information to determine immediate action items. For example, a flight conducted with an ultraviolet corona camera identified an insulator on one of the Company's 46 kV lines that was emitting a corona signature (see Figure 17 below), prompting an immediate replacement of the insulator to avoid an outage on the line, which would have interrupted 2,000 customers. The insulator in question was found to be cracked (which can result in emission of corona) and was in imminent failure status. In this figure, the image on the top left shows what the corona camera sees, with the red areas indicating that corona emissions are detected. The image on the top right shows the same insulators upon closer visual inspection, with the circle and arrow indicating where the insulator is cracked. The image on the bottom shows a closer view of the same insulator.

FIGURE 17
UV ANOMALY IDENTIFIED WITH CORONA CAMERA



For safety reasons, helicopters do not fly over approximately 400 specific miles of the HVD system. This is because it is difficult to land quickly and safely in the event of an emergency within the areas of these miles. Most of these "no-fly lines" are in urban areas. To inspect these lines, the Company performs a combination of driving, walking, or use of drones to complete patrols of all 400 of these miles over the period of two years with a target of 200 miles inspected per year. These inspections may include infrared and/or corona inspection using handheld cameras.

Q. Can you provide visual examples of assets identified through these inspections?

A. Figure 18 below is representative of common Priority 3 findings identified by helicopter inspection. These assets are in advanced stages of deterioration and at increased likelihood of failure. The arrows pointing to the cross arms indicate where they are cracked, splitting, and starting to fail as the arm is no longer straight. Figure 18 shows how quickly these assets can deteriorate once these reach a Priority 3 status. In Figure 19, the same structure is photographed three months apart with the left side of the image being the first photo taken and the right side of the image being the same structure three months later. These photos indicate noticeable deterioration in the cross arm, as light is showing through the image on the right but not in the original. When anomalies like the ones shown below are not addressed through this sub-program, failures follow, causing interruptions to a large number of customers and increasing spending in Demand Failures, where reactive work is more expensive.

FIGURE 18
PRIORITY 3 CROSS ARM DETERIORATION EXAMPLES



FIGURE 19
PRIORITY 3 CROSS ARM 3-MONTH DETERIORATION



In Figure 19, the left side is original, and the right side is three months later.

Pole Replacements

Q. What work is done in the pole replacements investment category?

A. Targeted pole replacements address poles identified during a previous annual pole inspection cycle that need to be replaced prior to the next inspection cycle.

Q. What is the Company's HVD pole inspection methodology and pole replacement criteria?

A. The Company's inspection and replacement criteria are provided in Exhibit A-107 (MLH-1) and are the same criteria the Company presented in other recent electric rate cases. The Company inspects HVD poles on an approximately 12-year cycle. A contractor performs visual inspections, sonic inspections, and bore testing on all poles 11 years old or older along specified line sections.

Q. How is this methodology and criteria used to identify poles in need of replacement as part of the pole replacement investment category in this sub-program?

A. HVD pole replacements in this sub-program are identified through the pole inspection program. Identified poles are grouped by line segment and reviewed to be included in a line rebuild project, line rehabilitation project, or individual pole replacement based on other line characteristics. For annual pole inspections, the Company identifies in advance which HVD lines will be inspected, so the Company knows which HVD lines will require pole replacements in the future based on inspection results. Given data about historical pole inspection failure rates, the Company can determine not only the HVD lines that will require replacements, but also how many poles on a given line are likely to require replacements. In 2025, the Company is planning to inspect 7,551 HVD poles across 160 different line sections as identified in Exhibit A-108 (MLH-2).

Q. Please further explain Exhibit A-108 (MLH-2).

A. In Exhibit A-108 (MLH-2):

- Column (a) identifies HVD line names and column (b) identifies how many poles will be inspected on that line;
- Column (c) identifies how many poles on each line the Company expects to be rejected during inspection, based on historical rejection rates; and
- Column (d) identifies the cost associated for the replacement of rejected poles.

In Case No. U-21585 and other prior rate cases, the Company assumed that 80% of its pole replacements would take place in this investment category in the HVD Lines Reliability sub-program, while the other 20% would be classified as "rush" pole replacement and be completed in the former HVD Lines and Substations Rehabilitation sub-program. In the instant case, the Company is simply grouping all pole replacements in the HVD Lines Reliability sub-program, although the Company will still prioritize some poles over others for faster completion if warranted by inspection results.

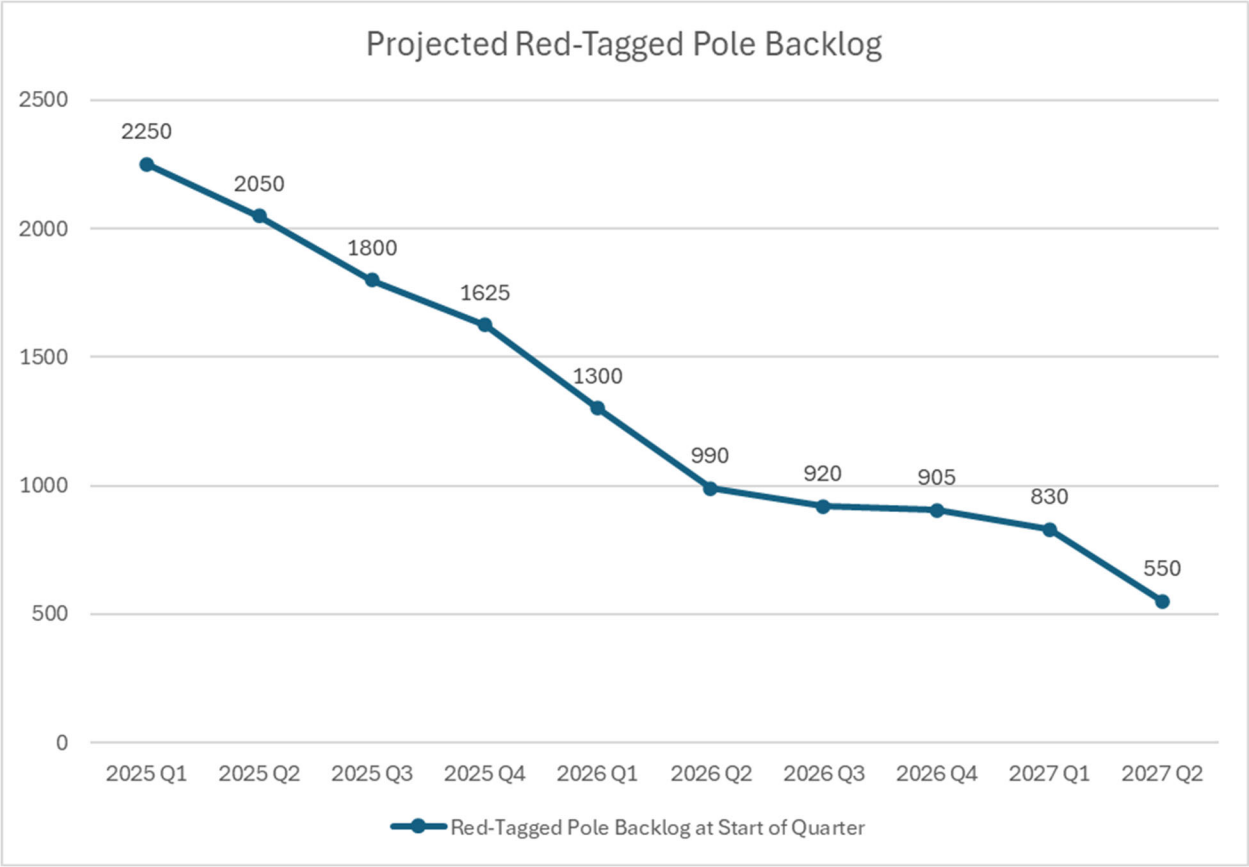
Overall, the poles identified during this inspection process, along with poles identified during previous inspections yet to be completed, will form the pole replacement plan for the test year.

Q. How many poles has the Company identified during previous inspection cycles and not yet replaced?

A. In the first quarter of 2025, the Company had a backlog of approximately 2,250 red-tagged HVD poles that were identified in earlier inspection cycles but have not yet been replaced. Those poles also inform the replacement plan for the bridge period and test year and will supplement poles identified by ongoing inspections outlined in Exhibit A-108 (MLH-2). The Company plans to clear this backlog through 2027, as shown in Figure 20 below. The figure takes into account the projected pole replacements in this sub-program for the bridge

and test year in addition to the projected number of poles expected to be rejected and added to the backlog from inspections during calendar years 2025 and 2026.

FIGURE 20
PROJECTED RED-TAGGED POLE BACKLOG



Q. Do pole inspections help identify projects for any other investment categories in this sub-program?

A. Yes. Switches are identified for replacement when the supporting pole is identified for replacement during the pole inspection program. As switch availability is critical for system operations, these locations are prioritized for replacement. Therefore, specific switch replacements in the test year will also be identified during 2025 pole inspections.

Q. Are there other reasons to replace HVD switches?

A. Yes. HVD switches, including Motor Operated Air Break Switches ("MOABS"), are critical pieces of equipment that aid in the efficient isolation of faults, which can shorten or mitigate outages for customers when a fault occurs. When these switches are inoperable, it often results in more customers experiencing an outage and/or customers remaining without service longer than if the switch had been available for operation. These switches are identified for replacement through field operations feedback on operability concerns and inspections. For example, MOABS are inspected regularly as their controls require power to operate, and since they are called on to operate when the lines they are attached to lose power, batteries provide power to the control of the MOABS to allow them to operate appropriately. Periodic battery replacement ensures that power is always available to operate the device. MOABS are tested annually to ensure the controls are in proper working order and the batteries are replaced every three to four years, or sooner as needed.

In Case No. U-21585 and prior cases, the Company performed switch replacements in both the HVD Lines Reliability and former HVD Lines and Substations Rehabilitation sub-programs. In the instant case, the Company is now combining all switch replacement work in HVD Lines Reliability.

Line Sensors

Q. What kind of work is done in the Line Sensors investment category?

A. The Company installs line sensors on HVD lines to provide increased visibility into abnormal activity on the HVD system. Line sensors detect small variations in voltage and current patterns, when and approximately where abnormal conditions are happening, allowing the Company to investigate and take action before a possible failure occurs. In

addition, when a fault does occur, line sensors can help pinpoint the location of the failure leading to quicker response, isolation, and restoration of service. Collected data aids in project identification for other investment categories within the HVD Lines Reliability sub-program. The Company continues to install line sensors with our switches to improve isolation times reducing SAIDI and Customer Average Interruption Duration Index ("CAIDI").

Q. Does the Company have line sensors installed anywhere else on the system? If so, what benefit has been realized after installation?

A. Yes, the Company has approximately 12,000 line sensors installed on the LVD system and 500 installed on the HVD system. As mentioned above, line sensors are being used to help identify abnormal line conditions that alert the Company to a possible issue. As a result, the Company has been able to investigate and correct these issues prior to them becoming faults and interrupting service to customers. When faults do occur where line sensor data is available, the data is being used to help locate the specific area of line that experienced the fault and remotely isolate the fault or routing field personnel to those spots for quicker response, isolation, and restoration of service.

ROW Acquisition

Q. What is the purpose of ROW acquisition in this sub-program?

A. The Company may need to acquire new rights of way, or expand existing ones, for a number of reasons. New rights are often needed for relocation of existing lines during rebuild projects. Expansion of existing rights is often required when the Company is rebuilding a line in the existing corridor but cannot take the line out of service, and therefore needs a wider ROW so the Company can continue providing service while building a new line

adjacent to the existing one. Additional rights may also be required when rebuilding a line to include larger conductor, requiring larger structures and larger structure supports. Finally, additional rights may be required to bring existing easements to current standards, allowing access for modern construction equipment and tree clearing standards.

Q. How do you calculate the amount of ROW dollars needed for this sub-program?

A. The Company projects that it will cost $200,000 per mile for updating and expanding existing land rights needed to support HVD line rebuilds and pole top rehabilitation projects, based on the most recent actual ROW costs for an executed project. The Company is projecting to spend $12,667,000 in the bridge and $11,000,000 in the test period to support the acquisition of 63 miles and 55 miles of additional land rights, respectively.

HVD Lines Reliability: Overall Investment and Benefits

Q. What is the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the HVD Lines Reliability sub-program?

A. The Company is projecting HVD Lines Reliability capital expenditures of $133,667,000 in the bridge period and $107,667,000 in the test year. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 21 below.

FIGURE 21

HVD LINES RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND PROJECTS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Benefit (customer minutes)	Test Year Capital	Test Year # of Units	Benefit (customer minutes)
Line rebuilds (miles)	$38,614,000	13	329,517	$35,743,000	65.8	1,371,211
Pole top rehabilitations (miles)	$9,097,000	54.7	1,421,191	$11,996,000	116.1	3,102,814
Pole replacements	$54,856,000	2,010	2,572,172	$33,569,000	1,230	1,574,016
Switches (incl. SCADA additions)	$7,364,000	51	52,211	$7,942,000	55	56,306
Pole Top Assembly Replacements	$8,958,000	950	2,315,625	$5,658,000	600	1,462,500
Line Sensors	$2,111,000	168		$1,759,000	140	
Right of Way Acquisition	$12,667,000	N/A		$11,000,000	N/A	
Total	**$133,667,000**		**6,690,716**	**$107,667,000**		**7,566,847**

Q. What are the customer minute benefits shown in that table above?

A. As explained earlier in my direct testimony, customer outage minutes is a mathematical product of the number of customers that would experience an extended outage of electrical service, and the duration in minutes of that outage, if a proposed project is not completed and the asset fails. A reliability project will lead to avoided future customer outage minutes by either reducing the probability of failure leading to an outage, the duration of the outage, and/or the number of customers impacted by the failure and subsequent outage. Calculations are based on assumptions for the number of impacted customers, outage

duration, failure rate, and the amount of units impacted. Assumptions are based on historical actual failures versus asset population, average number of customers impacted by lines events, and traditional response duration. Figure 22 below provides these assumptions used in bridge and test period calculations for the HVD Lines Reliability sub-program.

FIGURE 22
HVD LINES RELIABILITY CUSTOMER OUTAGE MINUTES ASSUMPTIONS

Project Type	Assumed Customer Impact	Assumed Duration (minutes)	Assumed Failure Rate
Pole Replacements	3900	250	0.021
Switch Replacements	3900	250	0.021
Individual Pole Top Assembly ("PTA")	3900	250	0.04
HVD Other Projects	3900	250	0.021
HVD Line Rehabilitation per mile	Note 1	Note 2	0.02
Line Rebuilds Unshielded	Note 1	Note 2	0.032
Line Rebuilds Obsolete Conductor/ Shielded	Note 1	Note 2	0.022
Line Rebuilds Standard Conductor/Shielded	Note 1	Note 2	0.02

Note 1: Based on the customers fed from that specific line.
Note 2: Target restoration time based on system configuration. 125 Minutes for a looped line, 250 minutes for a radial line segment off a looped line, and 310 minutes for a complete radial line segment.

Q. What is the basis of the Company's requested spending level for the bridge period and test year in this sub-program?

A. The requested spending levels are based on the total of all costs in the Company's workplan. The costs for individual projects are developed based on information from actual project expenditures over the past five years that have been refined to take into consideration the project location, expected site conditions, project specific material needs, and any known

anomalies in costs. The projected spending amounts for the bridge period and test year are determined by the combined costs of individual, planned projects and will allow the Company to complete the projects listed, and deliver the benefits defined, in Figure 11 above. The capital projects planned for the bridge period and the test year, as well as their investment categories, locations, and benefits to reliability, are shown in Exhibits A-109 (MLH-3), page 1, and A-110 (MLH-4), page 1. Pole replacements will be identified based on the process discussed above and reflected in Exhibit A-108 (MLH-2), with further replacements in the test year also identified based on inspections done during 2025 and 2026. It is important to note that projects can span multiple years, so the dollar amounts reflected in the exhibits are only the amounts that will be spent in the indicated time periods and customer minute benefit is realized during the year of project completion.

Q. Overall, what benefits will customers realize through the Company completing work in the HVD Lines Reliability sub-program?

A. As discussed in the executive summary of my direct testimony, customers realize improved reliability and resiliency through the Company completing this work. Specific benefits of the bridge period and test year planned projects are identified in terms of customer outage minutes avoided. The customer outage minutes avoided for the bridge period and test year HVD Lines Reliability projects are quantified in Exhibits A-109 (MLH-3), page 1, and A-110 (MLH-4), page 1.

These investments also improve the asset health of critical HVD components that would result in thousands of customer interruptions at a time when they fail. By improving the HVD system, customers will experience fewer outages and have faster restoration when outages do occur. HVD Lines Reliability investment is a component of the plan to achieve

the Company's reliability outcomes as outlined in the Reliability Roadmap, as well as the overall SAIDI improvements discussed by Company witness Kelly. Specific contributions of the HVD Lines Reliability sub-program to SAIDI improvements are presented in the direct testimony of Company witness Kelly.

While investment in HVD Lines continues to support a downward trend in overall SAIDI impact, increased investment in this category will also provide a significant value in proactive mitigation of deterioration and asset health risk, as discussed above and in the Reliability Roadmap, and quickly fixing anomalies identified through inspections will prevent significant interruptions to customers before they occur.

Q. Does the Company consider any alternative approaches to the HVD Lines Reliability projects?

A. Yes, for each potential project the Company considers three options: line rebuild, pole top rehabilitation, or addressing multiple individual system component degradation. As described above, there are multiple factors that guide what approach is selected for each given project.

Q. What is the risk if the Company does not perform this work?

A. An additional approach would be to not complete this work, which would result in the degradation of assets, decreases in reliability, and an increase in threats to safety for customers and Company workers. This would also impact system resiliency by affecting how quickly customers can be restored. Customers would see an increase in outages as system degradation would outpace system corrections. This is not prudent, as it would result in more outages in service and increased costs to the customer in the long run as equipment would have to be replaced on an unplanned basis.

Q. What has been the historical actual spending in the HVD Lines Reliability sub-program for the past five years?

A. The historical actual costs by investment category for HVD Lines Reliability are shown in Exhibit A-113 (MPK-3), line 8. The Company's historical actual spending in the HVD Lines Reliability sub-program for the past five years is also shown in Figure 23 below.

FIGURE 23
HVD LINES RELIABILITY HISTORIC EXPENDITURES

2020	2021	2022	2023	2024	5-Year Average
$22,290,000	$58,092,000	$42,565,000	$21,703,000	$32,264,000	$35,383,000

Q. Please explain if the spending in any of the five historical years is a significant outlier.

A. In 2021, spending was increased to align with the Company's workplan outlined in the 2021 EDIIP, and to the Company's overall level of investment approved by the Commission in Case No. U-20697. Spending was reduced in 2023 to align with the Company's overall approved level of investment in the settlement approved by the Commission in Case No. U-21224.

Q. How would these historical expenditures look if they included the work that was previously done in the former HVD Lines and Substations Rehabilitation sub-program?

A. If one looked at the historical investments in HVD lines that were done in the former HVD Lines and Rehabilitation sub-program, the totals would be those reflected in Figure 24 below.

FIGURE 24
HVD LINES RELIABILITY HISTORICAL EXPENDITURES PLUS HISTORICAL REHABILITATION WORK

	2020	2021	2022	2023	2024	5-Year Average
HVD Lines Reliability Historical	$22,290,000	$58,092,000	$42,565,000	$21,703,000	$32,264,000	$35,383,000
HVD Lines Rehabilitation Historical	$8,622,000	$10,204,000	$13,823,000	$8,793,000	$11,484,000	$10,585,000
Total	$30,912,000	$68,296,000	$56,388,000	$30,496,000	$43,748,000	$45,968,000

Q. What are the historical unit costs for each of the HVD Lines Reliability investment categories?

A. The historic unit costs for each category are provided in Figure 25 below:

FIGURE 25
HVD LINES RELIABILITY INVESTMENT CATEGORY UNIT COSTS

Investment Categories	2020	2021	2022	2023	2024	5-Year Average
Line rebuilds	$358,800/ mile	$1,029,600/ mile	$455,500/ mile	$1,675,300/ mile	$741,800/ mile	$717,700/ mile
Pole top rehabilitation miles	$86,100/ mile	$123,500/ Mile	$75,700/ mile	$72,100/ mile	$113,700/ mile	$100,300/ mile
Individual pole top replacements	$8,100/PTA	$10,300/PTA	$9,900/PTA	$8,400/PTA	$10,200/ PTA	$9,400/PTA
Pole replacements	$20,600/ pole	$24,200/Pole	$27,800/pole	$25,700/pole	$33,200/ pole	$26,800/ pole

Q. Please explain any variation in unit costs over time.

A. Individual projects can vary widely in cost from project to project based on specific project conditions, and as a result, the year-end per-unit average cost can also vary. For example, in Case No. U-20134, the Company considered 20 random work orders for pole replacements, encompassing 240 total pole replacements, and found an average cost of $18,800 per pole for that sample. However, considering each of those 20 work orders individually, unit costs ranged from $10,300 per pole to $29,300 per pole. Some of those

work orders involved replacing poles in easier to reach locations than others or involved working in differing weather conditions. Furthermore, HVD Lines Reliability projects often extend from one year into the next, as the primary construction timeframe for these projects is October through May. This construction timeframe is due to the peak loads seen during the summer months, and the unavailability to take sections of the HVD system out of service for replacement during those months. This timeframe also does not coincide with the Company's fiscal year, causing variations in unit costs as money is spent in one year while the units for the completed project are counted in the next year. In both 2021 and 2023, the Company spent significant amounts for line rebuild projects that were not fully completed until 2022 and 2024, respectively. Consequently, there is some spending shown in 2021 or 2023, while the project's units are counted in 2022 or 2024, affecting the apparent unit costs for those years. This is also the case when comparing the bridge period and test year in the instant case, as the bridge period includes work on multiple projects that will not be completed until the test year.

b) <u>HVD Substations Reliability</u>

Q. Please explain the HVD Substations Reliability sub-program.

A. The HVD Substations Reliability sub-program ensures the long-term safe and reliable operation of HVD substations, and ensures the ongoing asset health of HVD substations, with spending to make needed replacements of existing substation equipment. HVD Substations Reliability projects are identified and prioritized based on both asset health data and inspection results, as discussed below.

Q. Please provide a general overview of HVD substations and their purpose in the HVD system.

A. HVD substations take power from the Michigan Electric Transmission Company ("METC") 138 kV system and drop the voltage to feed the Company's 46 kV lines, that in turn feed the Company's LVD substations. HVD substations are designed with redundancy such that the failure of a single component in an HVD substation will typically not result in outages to customers. However, to facilitate repairs or construction, the HVD system is sometimes temporarily configured in a manner that may remove a layer of redundancy; additionally, if failures of multiple components in a substation occur in the same window of time, this could result in customer outages. While rare, these outages can have a significant SAIDI impact (two minutes of SAIDI or more, or greater than 1% of the Company's recent annual historical performance) when they do occur. In addition, there are many HVD substations that are now well beyond their intended design life, increasing the probability of major outages. To address these concerns, some HVD substations are being rebuilt under the Transformer Bank Replacements and Substation Rebuilds sub-program, which is discussed later in my direct testimony. Individual pieces or small groups of equipment that are of concern are addressed here, under the HVD Substations Reliability sub-program.

Q. What investment categories are included in the HVD Substations Reliability sub-program?

A. This sub-program consists of four investment categories:

a. circuit breaker and circuit switcher replacements;

b. transformer bushing replacements;

c. switch replacements; and

d. other targeted replacement programs for specific equipment, such as voltage transformer replacements and substation lightning arresters.

The replacement rationale for each investment category is included in Figure 26 below.

FIGURE 26
HVD SUBSTATIONS RELIABILITY REPLACEMENT RATIONALE

Replacement Category	Rationale for Replacement	Impact to Reliability
Circuit Breaker and Circuit Switcher	Obsolete Parts	Failure can cause a much larger number of customer outages if it occurs during a line fault.
Transformer Bushings	Higher failure rates than average bushing	Failure can cause customer outages if bushings fail. Bushing failures can also cause entire transformers to fail at significant cost.
Switches	Obsolete switches (replaced in conjunction with other substation work)	Failure can affect ability to remove equipment from service. Can significantly affect outage duration and repair costs.
Other Targeted Replacement	Safety hazard (potential to explode)	Failure can affect proper operation of substation. Failure can affect ability to power test equipment, lighting, etc.

Q. Has the Company made any changes to the work being done in the HVD Substations Reliability sub-program since Case No. U-21585?

A. As noted earlier in my direct testimony, some work that was included in the former HVD Lines and Substations Rehabilitation sub-program in Case No. U-21585 and prior cases has been transferred to the HVD Substations Reliability sub-program in the instant case. Specifically, the former HVD Lines and Substations Rehabilitation sub-program included projects to address issues with substation equipment identified during inspections. That work has been transferred to HVD Substations Reliability and inserted into the existing investment categories in this sub-program; no new investment categories have been defined.

Q. Please explain these substation inspections.

A. There are several inspection programs for substation equipment ranging from monthly patrol inspections, infrared inspections, to inspections of individual pieces of substation

equipment. Similar to HVD lines inspections, these equipment inspections allow the Company to be proactive in identifying equipment near failure and generating short cycle planned work to replace an asset when that failure presents a risk to customer reliability and/or system operability and are critical for monitoring and addressing asset health concerns before the asset fails. Just as HVD lines inspections identify deteriorated crossarms and other components before they fail, substation inspections provide advance warning on a wide variety of substation assets in failing health.

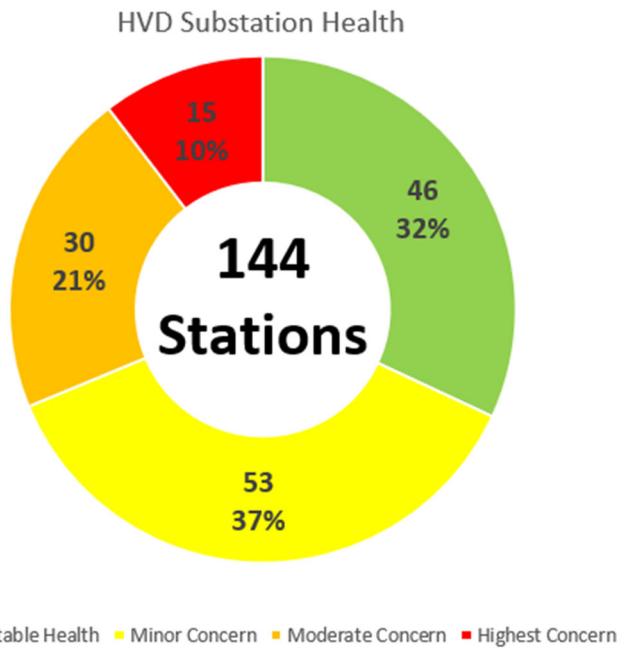
After identification, the work is planned, prioritized, and executed to mitigate the risk of unnecessary outages for customers or limitations to system operability. Lower priority issues that must be addressed but are not at imminent risk of impacting customer reliability or system operability, are planned for future years. When inspections identify anomalies indicating a high likelihood of failure that would cause an impact to customer reliability and/or system operability, the work is planned and executed to address the priority item in a short cycle fashion. Examples of equipment that would fall into this portion of this category include but are not limited to regulators, cap controllers, bushings, circuit breakers, lightning arresters, and switches.

Q. How is the HVD Substations Reliability sub-program delivering on the intent of the Reliability Roadmap?

A. As discussed in the Reliability Roadmap, the Company's primary strategy for HVD substations is to address substation components – particularly circuit breakers, transformer bushings, and switches – with poor asset health through a workplan that replaces those assets that have been identified as having poor health, and/or assets that have been identified through inspections, as discussed above. As the Reliability Roadmap notes, 10% of HVD

substations are a high priority for repair or replacement and an additional 21% show cause for moderate concern, as shown in Figure 27 below. Compared to the Company's assessment of HVD substation asset health at the end of 2023, this figure shows fewer substations in the highest concern category, reflecting projects completed in the past year, but more substations in the moderate concern category. The increase in substations in the moderate concern category is indicative of deterioration progressing faster than the Company's rate of investment.

FIGURE 27

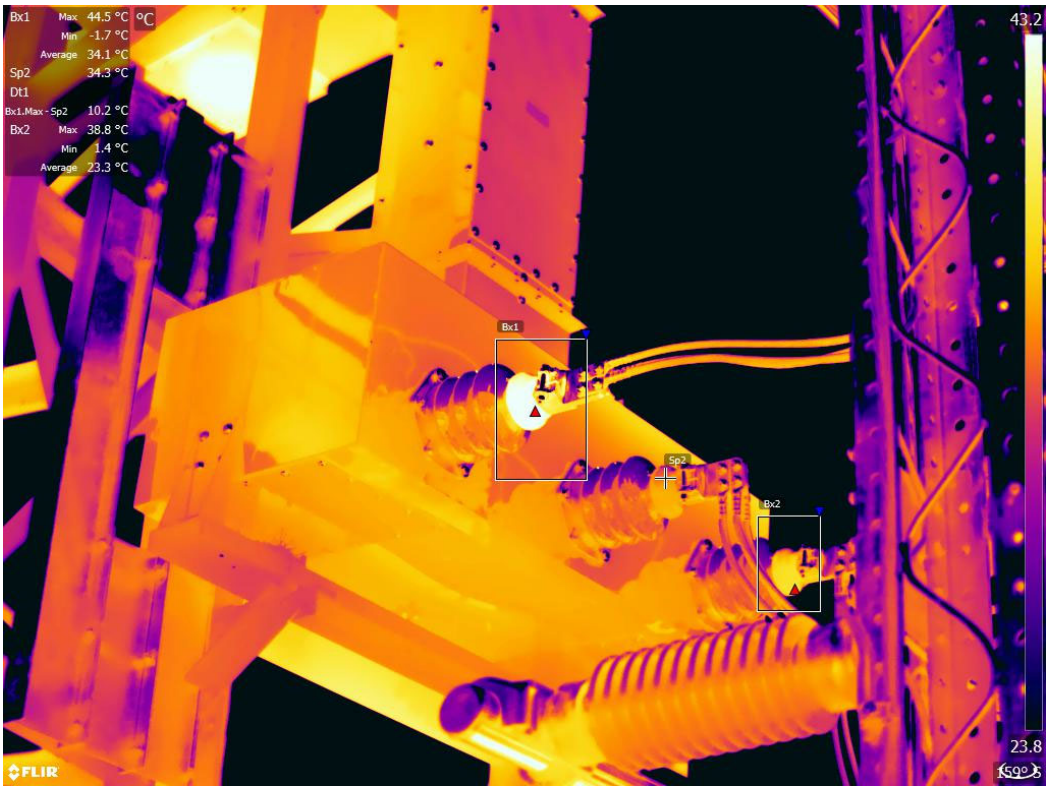


To address these risks, the Company established a plan in the Reliability Roadmap to increase investment in HVD substations. Much of the increased investment to address these risks will be performed in the HVD Lines and Substations Rehabilitation sub-program discussed later in my testimony, but increased investment in this sub-program will also address asset health issues in HVD substations.

Q. How does the Company identify specific pieces of equipment with poor asset health for replacement in the HVD Substations Reliability sub-program?

A. To identify substation equipment that may need replacement, the Company uses an asset health model that takes multiple inputs and analytic processes to aggregate numerous data sources to best target assets in poor health that are likely to cause reliability issues in the near term if they are not addressed. Based on the data in the asset health model, the timeline for correction can range from 1-2 months, to prevent a near term failure, up to a planned replacement coordinated with other work at the site in the following year. The inputs into the health model come from the multiple inspections within the Company's substation programs like infrared inspections, routine substation patrols, and diagnostic testing of transformers and breaker oil and gases. The overall philosophy and methodology behind the asset health model was discussed earlier in my direct testimony. Figure 28 below shows an example of an infrared anomaly of an insulator identified during inspection, which the Company would proactively address prior to a failure that would impact customers.

FIGURE 28



The model used to monitor the asset health of HVD substation assets is leveraged to identify specific areas to target investments based on likelihood, consequence, and severity of an asset's failure also known as that asset's risk. Projects are prioritized to deliver the greatest reliability improvements for the customer.

Q. What benefits will customers realize through completing the HVD Substations Reliability sub-program work, as proposed in this case?

A. The primary benefit of investing in HVD Substations Reliability at the levels proposed in the instant case is the improvement of asset health, which lets the Company prevent future potential high-impact outages that would result in significant customer interruptions and loss of system resiliency. As shown in Figure 27 above, 31% of HVD substations have either moderate or high concerns regarding asset health. While HVD substations are not a large overall contributor to systemwide SAIDI, HVD Substations Reliability investment

does improve overall system reliability for the customer, resiliency in the HVD lines system, in addition to reducing asset health risk. The projected customer outage minutes avoided from HVD Substations Reliability investments are also discussed below and shown in Figure 29. Customer outage minutes saved are calculated based on assumptions for number of impacted customers, outage duration, failure rate, and the amount of units impacted. Assumptions are based on historical actual failures vs. asset population, average number of customers impacted by substation events, and historical response duration. The table below illustrates the assumptions used to calculate customer outage minutes avoided for HVD Substations Reliability.

Project Type	Assumed Customer Impact	Assumed Duration (minutes)	Assumed Failure Rate
Circuit Breakers	3900	240	0.00067
Bushings	3900	250	0.028
HVD Animal Mitigation	5850	120	0.067
Potential Transformer ("PT") Replacements	2000	240	0.01
Station Transformer Replacements	5850	240	0.005
Substation Rebuilds	11700	240	0.028

Q. Can you provide more detail on the circuit breaker and switcher replacement investment category?

A. Circuit breakers and circuit switchers are critical components of the HVD system, designed to minimize customer outage impact and mitigate equipment damage when the system

experiences and clears an electrical fault. The replaced units are generally 1950s and 1960s vintage oil or gas circuit breakers, given their poor performance, asset health, and the increasingly limited availability of parts. In addition, there are some early models of circuit switchers (notably certain S&C models) that have been deemed obsolete and have been replaced under this program.

Q. Can you provide more detail on the transformer bushing replacement investment category?

A. Transformer bushing replacements include bushing types with high failure rates, such as Type U, and bushings with observed degradation as identified through testing and inspection. Type U bushings have been known to lose dielectric strength due to a design characteristic that can result in violent failure. This failure often results in oil spraying on equipment, possible PCB contamination, and damage to the transformer and/or adjacent equipment which can cause multiple minutes of SAIDI per event. The Type U bushings are known industry-wide to have higher failure rates than average bushing failure rates. The Company has been systematically replacing Type U bushings for several years, based on customer impact and consideration of other scheduled work in the substation to maximize workforce efficiency and utilization. The Company is also focusing on replacing Type O+C bushings due to a known oil defect used in manufacturing. Some O+C bushing oil is contaminated with corrosive sulfur that leads to degradation of the conductor and condenser structure within the bushing. These can also fail violently resulting in the same concerns noted above with the Type U bushings.

Q. How did the Company develop the projected expenditures for the bridge period and test year in this sub-program?

A. Spending is based on the projected number of projects in each substation reliability category. Project costs were determined based on historical actual costs of comparable projects of similar scope.

Q. What is the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the HVD Substations Reliability sub-program?

A. The Company is projecting HVD Substations Reliability capital expenditures of $47,322,000 in the bridge period and $39,680,000 in the test year as shown in Exhibit A-115 (MPK-5), line 4, columns (e) and (f). The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 29 below. Planned projects are listed in Exhibit A-109 (MLH-3), page 2, for the bridge period and in Exhibit A-110 (MLH-4), page 2, for the test year.

FIGURE 29
HVD SUBSTATION RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Anticipated Customer Minute Savings	Test Year Capital	Test Year # of Units	Anticipated Customer Minute Savings
Circuit breaker/switcher replacements	$20,038,000	63	39,312	$23,737,000	74	46,176
Transformer bushing replacements	$2,185,000	17	1,043,340	$1,356,000	10	695,520
Switch replacements	$2,822,000	46	941,850	$1,829,000	34	696,150
Other	$22,277,000	169	832,710	$12,758,000	83	344,838
Total	**$47,322,000**			**$39,680,000**		

Q. What has been the historical actual spending in the HVD Substations Reliability sub-program for the past five years?

A. The historical actual costs by investment category for the HVD Substations Reliability sub-program are shown below in Figure 30.

FIGURE 30
HVD SUBSTATIONS RELIABILITY HISTORIC EXPENDITURES

2020	2021	2022	2023	2024	5-Year Average
$6,480,000	$3,456,000	$3,993,000	$3,262,000	$5,715,000	$4,581,000

Q. How would these historical expenditures look if they accounted for work that was previously done in the former HVD Lines and Substations Rehabilitation sub-program?

A. If one looked at the historical investments in HVD lines that was done in the former HVD Lines and Rehabilitation sub-program, the totals would be those reflected in Figure 31 below.

FIGURE 31
HVD SUBSTATIONS RELIABILITY HISTORICAL EXPENDITURES PLUS HISTORICAL REHABILITATION WORK

	2020	2021	2022	2023	2024	5-Year Average
HVD Substations Reliability Historical	$6,480,000	$3,456,000	$3,993,000	$3,262,000	$5,715,000	$4,581,000
HVD Substations Rehabilitation Historical	$5,045,000	$5,211,000	$4,712,000	$4,826,000	$4,403,000	$4,839,000
Total	$11,525,000	$8,667,000	$8,165,000	$8,088,000	$10,118,000	$9,313,000

Q. How do the projected bridge period and test year investment compare to historical investment in this sub-program?

A. As discussed above, the Reliability Roadmap defined a plan to increase investment in HVD substation assets. The bridge period and test year in this case in this sub-program show increases in alignment with the Reliability Roadmap.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Many projects in this sub-program often include additional requirements beyond just the basic asset investment. This is common when system outages or reconfigurations are needed to allow workers to perform work on these assets safely. As these outages and reconfigurations are sometimes difficult to schedule, when they do take place additional scope can be added to optimize the work that can be accomplished during a system reconfiguration or scheduled outage. For example, switches are often replaced when work is being done to replace a circuit breaker, as work conditions are ideal for addressing the switches while the breaker is being replaced. The historic unit costs for each investment category in the HVD Substations Reliability sub-program are included in Figure 32 below.

FIGURE 32
UNIT COSTS FOR HVD SUBSTATIONS RELIABILITY

Investment Categories	2020	2021	2022	2023	2024
Circuit breaker/switcher replacements	$136,037	$116,673	$118,220	$157,560	$132,986
Transformer bushing replacements	$78,571	$107,997	$105,017	N/A	$136,738
Switch replacements	$25,700	$47,331	$41,328	$42,269	$108,397
Other	$36,471	$5,698	$51,840	$16,642	$40,293

Q. Why do transformer bushing replacements not have a unit cost in 2023?

A. In 2023, there were no bushing replacement projects completed in this sub-program. All bushing replacements occurred on failed bushings or as part of projects in the former HVD Lines and Substations Rehabilitation sub-program, and the Company did not break out these unit costs in that sub-program.

Q. Please explain any variation in unit costs year-over-year.

A. Unit costs vary from year to year, as the apparent unit costs in this sub-program represent total project costs, not necessarily the cost to replace a single unit of equipment. Projects in this sub-program can vary greatly in scope, from a single piece of equipment being replaced to multiple pieces depending on the health of the assets at the substation. This is especially true for circuit breaker and circuit switcher projects, which require a significant amount of clearance to perform the work. Because of this, the Company expects to replace more than just individual breakers or switchers on the project. These projects will have expanded scope to include bus work modifications, additional switch replacements, and adjacent wiring to the control enclosures.

Additionally, the "Other" investment category has included a wide range of types of projects over the years, making year-to-year cost comparisons difficult on a per-unit basis.

c) <u>Transformer Bank Replacements and Substation Rebuilds</u>

Q. Please explain the Transformer Bank Replacements and Substation Rebuilds sub-program.

A. The Transformer Bank Replacements and Substation Rebuilds sub-program is dedicated to 1) the capital repair or replacement of HVD and SEC substation equipment (primarily large substation transformers ranging in size from 2 MVA to 100 MVA), and 2) rebuilds of entire

substations. Both types of work typically consist of large projects that take place over multiple years in stages, with costs incurred across multiple years before the project is complete.

Q. Why does the Company replace large substation transformers and rebuild HVD and SEC substations?

A. When the asset health of an entire substation or of a large transformer within a substation deteriorates, the Company replaces them to reduce the risk of assets failing and causing impacts to customer reliability. Replacing these assets proactively prevents long duration outages that can often be 18-24 hours in length as the replacement of these assets often requires the Company to use an emergency mobile substation set. A mobile substation consists of substation equipment on a trailer that can be used to maintain service to an area while work is being done inside a substation. In an emergency situation when a major failure in a substation has occurred it can often take 18-24 hours to deliver and hook up a mobile substation, which can lead to two or more SAIDI minutes per incident. As identified in the Reliability Roadmap, many substation assets have outlived their initial intended lifespan, with a significant percentage of HVD substations facing high or moderate asset health concerns. While maintenance and inspection practices have, to date, allowed these assets to perform beyond their normal end of life, substation rebuilds and transformer replacements are needed to address these higher-risk assets.

Q. Are these projects larger and longer-term than projects in the HVD Substations Reliability sub-program?

A. Yes. These are major investments and require multiple years to plan and secure equipment. A transformer can take over two years to obtain after ordering and cost anywhere from

$1 million to $5 million, depending on size and voltage rating. The multi-year nature of these projects means that different project stages can take place in different years. For example, one year may involve ROW procurement, another year may involve material procurement, another year may involve construction, etc. The multi-year planning component of these large projects makes it particularly important for the Company to have predictably and consistently approved cost recovery on a year-to-year basis.

Q. How does the Company determine if it will rebuild an entire substation or just replace transformers within the substation?

A. Multiple factors are taken into consideration when deciding to replace a transformer or rebuild a substation. If a transformer bank and bushings are deteriorated, but the rest of the substation is still in good operating health, then the Company will opt to replace the deteriorated transformer. If multiple components of a substation are deteriorated, it becomes more economical for the Company to rebuild the station instead of replacing a large number of components individually. Figure 33 below shows an illustrative example of the asset health model for HVD substations. In this example, *Sub A* would be a strong candidate for a full rebuild, as the Company would need to address the transformers, breakers, switches, and structure or concrete damage. Conversely, *Sub B* would be a likely candidate for a transformer bank replacement, as the primary driver of the score for that station is the failing health of the transformer bank itself.

FIGURE 33
ILLUSTRATIVE SUBSTATION ASSET HEALTH MODEL

Category	Points per Occurance	Sub A	Sub B	Sub C
AC/FP/REC Wound	25	0	0	0
Age 50+	20	1	1	1
Oil or N2 Leaks	10	1	1	0
Transformer Internal Infrared	10	0	1	0
DGA Score	20	1	0	0
Brand A Bushing Issue	15	1	0	0
Brand B Bushing issue	5	0	0	0
IR P1/P2	20	0	1	0
Doble or Elec Test Issues	15	0	1	0
Transformer & Bushings Total		65	75	20
REG/LTC TOA R3/4	25	1		
IR P1/P2	20			
REG/LTC Total		25	0	0
OCB > 50 Yrs; GCB > 25 Yrs	5	7	3	1
3PH Reg/LTC Demand Order	10	1		
BRKR Oil or SF6 Gas Quality/Leaker	15		1	1
IR P1/P2	15			
Maint/RP Priority List	10			
Oil and Gas Circuit Breakers Total		45	30	20
99 & Cap Bank CSWs/VSW Issues	15	1		
SPT Watch List	10	2	1	1
Str & Concrete	5	1		
Other	5			
IR P1/P2	15		1	1
Ops Limiting Equip	20	1		
Station & Other Totals		60	25	25
Total Score Normalized		100	66.66667	33.33333
Gross Total		195	130	65

Q. How are investments in HVD substation transformer replacement projects aligned with the Reliability Roadmap?

A. The Reliability Roadmap states that the Company would need to replace an average of 12 transformers yearly between HVD and strategic customer substations to address transformers in poor asset health. Because these large transformers have a long lead time,

the number of replacements actually completed in a given year may vary from year to year. In the instant case, the Company is planning work related to 14 transformers in the bridge period and three transformers in the test year.

Because it can take more than two years to obtain a single transformer, the Company also places orders for transformers ahead of time to ensure they will be available in the years beyond this current case to support the increased replacement levels described in the Reliability Roadmap. The Company then makes "progress payments" on these transformer orders to ensure their timely delivery from the manufacturer. As indicated in Exhibit A-109 (MLH-3), page 3, line 14, and Exhibit A-109 (MLH-3), page 3, line 9, the Company is making progress payments in both the bridge period and test year. Making progress payments will allow the Company to ensure it has a larger supply of transformers in the future; the progress payments listed in my exhibits are for future deliveries of approximately 30 transformers.

Q. Why is the Company working on more transformer replacements in the bridge period than in the test year?

A. As stated above, the Company needs to acquire production slots to ensure adequate delivery of transformers, which is the purpose of the progress payments over the next few years. Additionally, the relative numbers of projects in the bridge period compared to the test year are related to resource availability in this sub-program as a whole. In the test year, the Company is doing more work on the Alma and Blackstone substation rebuild projects, which are discussed below. In the test year, these large projects will require more financial investment and will also require more materials and more workforce than in the bridge period (the substation rebuild projects themselves require multiple transformers). These

factors mean the Company will not do as many transformer replacement projects in the test year.

Q. How are investments in HVD substation rebuilds aligned with the Reliability Roadmap?

A. The Reliability Roadmap states that the Company will complete approximately 2-4 HVD and strategic customer substation rebuilds per year. HVD substation rebuilds are generally very large projects that span two to three years, so in any given year the Company will likely be performing some work on more than two projects at once, and the Company may not always bring two projects a year to final completion. Also, as noted above, substation rebuilds themselves require new transformers, so the number of substation rebuilds can be inversely correlated with the number of transformer replacement projects. In the bridge period in this case, the Company is performing work on four different substation rebuild projects (see Exhibit A-109 (MLH-3), page 3):

- North Belding Substation: Costs in the bridge period represent labor and materials to complete this rebuild of this station which included replacement of a transformer and several breakers. Final checkout and asset in service is scheduled for mid-year 2025.

- Buskirk Creek Substation: This is a brand-new substation on a new parcel that will replace the Wayland Substation once it is complete. Scope of work in the bridge period will include the development of a new substation site, construction of substation support structure, and installation of equipment.

- Armory Substation: This is a brand-new substation on a new parcel that will replace the Alma Substation once it is complete. Scope of work will include transformer procurement costs of two units, property acquisition, environmental assessment, permitting expenses, land survey, and engineering costs.

- Royal Substation: This is a brand-new substation to replace the existing Blackstone substation on a new parcel. Scope of work will include transformer procurement costs for two units, property acquisition, environmental assessment, permitting expenses, and engineering costs.

In the test year in this case, the Company is performing work on five different substation rebuild projects (see Exhibit A-110 (MLH-4), page 3):

- Buskirk Creek Substation: Costs in the test year represent completion of construction activities and final checkout before being put into service.
- Armory Substation: Scope to include continued transformer procurement and engineering costs. In addition, major materials like breakers, circuit switchers, capacitor banks, control enclosure, and structural steel will be procured.
- Royal Substation: Scope to include continued transformer procurement and engineering costs. In addition, major materials like breakers, circuit switchers, capacitor banks, control enclosure, and structural steel will be procured as well as land clearing/grading of the new site.
- Cement City Substation: Site preparation, which includes engineering and mobile pad work to support the rebuild of the Cement City Substation past the test period.
- Mecosta Substation: Site preparation, which includes engineering and mobile pad work to support the rebuild of the Mecosta Substation past the test period.

Q. Does the Company consider any alternative approaches to its substation investments in this investment category?

A. As discussed above, the first option is to address only the major asset or assets that are failing on an individual basis. If this can be done, it improves the overall health of the station with the minimum required scope and cost while addressing the risk in the most immediate timeframe. Full substation rebuilds are only done when there are multiple failing assets, which is then a more cost-effective option than replacing individual components. In the concept approval process, the Company reviews alternatives to address the main concerns at each site, and an alternative is selected that best addresses the main asset health concern while also minimizing impact to the grid and external stakeholders.

For the substation rebuild replacement projects, the projects were selected from a list of the 25 HVD bulk power substations evaluated as the highest priorities based on their

asset health considering inputs from multiple groups within the Company. Adjustments to the plan were then made based on geographic locations, other known large projects in progress for the Company and METC, and the ability to schedule outages. Rather than select from the list of possible substation locations for rebuilds, the other option would be to attempt to run each HVD substation component to failure, but this would result in more customer outages and increased costs to the customer in the long run as equipment would have to be replaced on a demand basis. Transformer replacement projects were selected in a similar manner, but prioritizing units with failing test data. Like the HVD substation rebuilds, the other option would be to run these units to failure, which would result in extended customer outages, due to the long lead time for manufacturing replacement units (there are a limited number of spare HVD transformers in stock), and the small number of mobile substations available for HVD voltages. When transformers fail prior to a scheduled replacement, it creates a significant strain on completing other planned work, as often the Company may have to reallocate a transformer meant for a replacement project to address an actual failure. This delays the benefit of completing the planned projects and causes cascading issues of rework for materials and resource allocation. At best, the result would be higher costs to customers for the replacement of these units since the work would be unplanned.

In the instant case, the Armory Substation (replacing Alma Substation) and Royal Substation (replacing Blackstone Substation) replacement projects are among the Company's 25 largest overall test year distribution projects, and the associated concept approvals are included in the Company's Part III filing requirements, which show additional details around how these projects were selected.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, in the Transformer Bank Replacements and Substation Rebuilds sub-program?

A. The Company is projecting Transformer Bank Replacements and Substation Rebuilds capital expenditures of $46,666,000 in the bridge period, and $37,667,000 in the test year as shown in Figure 34 below.

FIGURE 34
TRANSFORMER BANK REPLACEMENTS AND SUBSTATION REBUILDS INVESTMENT CATEGORY EXPENDITURES

Investment Categories	Bridge Period Capital	Benefit (Customer Minutes)	Test Year Capital	Benefit (Customer Minutes)
Large Transformer Replacements	$16,993,000	28,092	$6,584,000	21,060
Progress Payments on Transformers	$11,844,000	N/A	$14,770,000	N/A
HVD Substation Rebuilds projects	$17,829,000	157,248	$15,313,000	78,624
ROW for New Substations	$0	N/A	$1,000,000	N/A
Total	**$46,666,000**	185,340	**$37,667,000**	99,684

Q. Please list any projects that make up the requested spending level for the Transformer Bank Replacements and Substation Rebuilds sub-program during the bridge period and test year.

A. Identified projects for this sub-program are listed in Exhibit A-109 (MLH-3), page 3, for the bridge period and in Exhibit A-110 (MLH -4), page 3, for the test year. In Exhibit A-109 (MLH-3), page 3, lines 12 and 13 are two parts of the same project at the Delta College Substation. In the test year, the Company is also planning to spend $1,000,000 on ROW

acquisition for new substations projects. The Company has experienced recent procurement challenges related to the Armory (Alma) and Royal (Blackstone) rebuild projects, indicating a need to have this step completed earlier in the project timeline as to not delay the replacement of these substations. Procurement of ROW for projects beyond the test period is necessary to keep these future multi-year projects on track.

Q. Please provide an overview of historical spending for the investment categories in this sub-program.

A. The historical actual spending, from when work was included in the former HVD Lines and Substations Rehabilitation sub-program, is shown in Figure 35 below. Note that this figure does not represent all historical spending in the former HVD Lines and Substations Rehabilitation sub-program, only the spending on transformer bank replacements and on HVD substations rebuilds.

FIGURE 35
TRANSFORMER BANK REPLACEMENTS AND SUBSTATION REBUILDS HISTORICAL SPENDING

Investment Categories	*2020*	*2021*	*2022*	*2023*	*2024*	*5-Year Average*
Large Transformer Replacements	$1,522,399	$3,598,057	$4,682,117	$6,240,187	$2,934,464	$3,795,445
HVD Substation Rebuilds	$152,068	$10,845,480	$15,847,961	$6,081,940	$5,992,604	$7,784,011

Q. How were the bridge period and test year spending amounts determined for the HVD substation replacement projects investment category?

A. For HVD substation rehabilitation work, spending for the bridge period is based on projects identified in Exhibit A-109 (MLH-3), page 3. Spending for the test year is based on projects identified in Exhibit A-110 (MLH-4), page 3.

Q. How will customers benefit from investments in this sub-program?

A. Benefits in this sub-program fall into a few categories. First, these investments will deliver the customer minute benefits summarized in Figure 34 above. The projects address the assets in the worst health at the Company's most critical substations. By replacing transformers, and by replacing both transformers and other equipment when performing a rebuild, the Company is ensuring that the substation is ready to serve the area for the next 50+ years.

Q. What are the historical unit costs for this sub-program?

A. Because this sub-program consists of a small number of large projects that often take place over multiple years, there is not a meaningful way to calculate historical annual unit costs for this sub-program.

d) <u>LVD Substations Reliability</u>

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Substations Reliability sub-program.

A. The LVD Substations Reliability sub-program ensures the long-term safe and reliable operation of LVD substations, which are the interface point between the HVD lines and LVD lines on the Company's system. The Company's LVD Substations Reliability investments significantly reduce the risk of a customer experiencing a long duration outage. While customers in more urban areas often can transfer to an adjacent substation through LVD line switching in the event of a failure, for customers in more rural areas, there is no ability to transfer substations. This increases the likelihood that an outage could be longer in duration. To mitigate this risk, the LVD Substation Reliability sub-program has invested in several categories, including:

(i) new or rebuilt substations;

(ii) mobile substations;

(iii) animal mitigation;

(iv) substation transformer replacements; and

(v) regulator replacements.

Q. Please explain why it is necessary to install new substations or rebuild existing substations to enhance LVD substation reliability.

A. New substations with new line circuits improve reliability by reducing the overall length of circuits. Shorter circuit miles reduce outage exposure, and new circuits allow for modified line protection schemes that can reduce the number of customers that experience outages during outage events. New substations provide additional capacity that can be used for planned and emergent customer transfers to minimize outage duration, and distribution automation schemes can be installed to transfer customers between substations during outage events. Before a new substation is considered, a study is completed to compare the SAIDI, System Average Interruption Frequency Index ("SAIFI"), and CAIDI benefits along with the economic costs of the new substation alternative to traditional line solutions, and to consider long-term system capacity needs to optimize new substation locations. A new substation may be installed if the system reliability improvements and economic benefits are comparable to or exceed traditional line solutions.

Substation rebuilds are necessary due to working clearance constraints within the compact designs of substation structures commonly constructed in the 1950s and 1960s. Operations and maintenance personnel are not able to operate or replace equipment without de-energizing the entire substation due to unacceptable working distances from energized

components. This results in additional costs to use a mobile substation for planned projects or increases restoration time and the number of customer outages needed for emergent work, degrading the reliability of service provided to customers. Because of the new design and expanded dimensions, modern electronic reclosers and regulators do not fit within these compact structures without violating working clearances or electrical code clearances, i.e. National Electric Safety Code ("NESC") Rule 125, section A, titled "Working space about electric equipment: Working Space (600 Volts or Less)."

Q. What are mobile substations?

A. Mobile substations are compact semi-trailer mounted substations that can be moved around the state to restore interrupted service for long duration substation equipment repairs and replacements or to maintain service to customers during planned substation projects.

Q. Does installation of mobile substations improve reliability outcomes, including those set forth in the Company's longer-term distribution strategy?

A. Yes. Mobile substations are used to maintain service to customers during planned substation projects, for imminent failure concerns before interruptions occur, and to restore interrupted service, limiting the negative reliability impacts.

Q. What is the purpose of investment in animal mitigation measures?

A. Animals that meet energized substation components cause service interruptions and equipment damage. The purpose of each animal mitigation project is to keep animals, such as squirrels and raccoons, out of the substation, and to insulate equipment to extend touch potential if an animal gets into a substation, with specific measures chosen based on substation characteristics. Common animal mitigation measures include:

(i) one-inch mesh fence (squirrels can squeeze through larger mesh);

(ii) concrete gate foundations (minimizes gaps and frost heave that create gaps over time);

(iii) polycarbonate panels (three-foot panels installed at the top of the fence to mitigate animals from climbing over the fence);

(iv) pole wraps and line discs (installed on poles and wires outside the substation to mitigate aerial access to the substation);

(v) interior and exterior stone (eliminate gaps at the fence bottom to mitigate animals from crawling under the fence); and

(vi) bushing guards on regulators and reclosers to extend touch potential to mitigate contact to energized components should an animal climb on equipment.

The Company also typically clears vegetation within 10 feet from the substation fence, except if a city or township requires vegetation to be closer for screening purposes or if the substation fence is within 10 feet of the property line, and the adjacent property has vegetation up to the property line. The Company's animal mitigation standards do not include measures to prevent bird intrusions because birds can fly over fences and barriers, but mitigation measures such as bushing guards can mitigate touch potential on energized components.

FIGURE 36
DAMAGE FROM ANIMAL CONTACT



Q. How do the Company's proposed substation transformer replacement projects impact customer reliability?

A. Replacement of substation transformers that show evidence of degradation before failure occurs prevents service interruptions.

Q. How do the Company's proposed substation regulator replacement projects impact customer reliability?

A. Replacing substation voltage regulators that show evidence of degradation before failure occurs prevents service interruptions, improves service quality, and prevents customer equipment damage that can occur with unregulated service voltage.

Q. Has the Company recently added any new types of investment to the LVD Substation Reliability sub-program?

A. Yes. Starting in 2024, three work items were moved to the LVD Substation Reliability sub-program from other sub-programs:

(i) HVD line work associated with new and existing LVD substation projects;

(ii) ROW procurement; and

(iii) Distribution Supervisory Control and Data Acquisition ("DSCADA").

HVD line work and ROW procurement associated with new and existing LVD Substation Reliability sub-program projects were previously part of HVD Lines and Substation Capacity sub-program investments. To improve investment categorization and project cost tracking, HVD line work and ROW procurement associated with LVD Substation Reliability projects are now incorporated into the LVD Substation Reliability sub-program. Projects to install DSCADA systems in existing LVD Substations were previously part of

the Grid Automation sub-program and are now an investment category within the LVD Substation Reliability sub-program.

Q. Does the Company have historical costs available for HVD line work associated with new and existing LVD substations projects and ROW procurement?

A. Prior to moving these two items to the LVD Substation Reliability sub-program in 2024, the costs were not tracked separately, so historical costs are not available.

Q. What is DSCADA?

A. The Company has been installing DSCADA on its LVD substations for several years, and now considers it a standard business practice, which is why it is no longer considered a Grid Modernization effort and has been moved into this sub-program.

DSCADA is a foundational system that gathers real-time grid data and provides substation device remote control capability. When DSCADA is installed at a substation, it includes a Remote Terminal Unit ("RTU"), a local device that facilitates communications with substation devices, and remote software systems. The communications component uses a cellular modem to transmit more than 300 data points within the substation to the Advanced Distribution Management System ("ADMS"). DSCADA investment includes the required construction and installation of automation equipment at the substation, as well as adding smart devices and controllers to core substation equipment.

Q. How does the Company identify LVD Substations Reliability projects?

A. The Company uses several inputs and analyses to determine how to best target LVD Substations Reliability issues. These inputs help identify specific areas to target investments based on probability of future issues and help to prioritize projects that will

deliver the greatest reliability improvements based on SAIDI and SAIFI. These inputs include:

- LVD circuit planners – Analyze historical outage trends on the LVD lines system to identify areas of greatest reliability concern based on total number of outages, trends in reliability performance, and potential reliability impact;
- Input from field operations and other departments – Inform substation planning engineers on operational concerns and system constraints identified during substation inspections, as described by Company witness Kelly, that may trigger necessary projects, such as working clearance constraints;
- Animal intrusion data – Animal mitigation projects are implemented to mitigate animal-caused substation outages;
- Equipment trend data – Planned replacement of substation equipment may be triggered with trend data that indicates degrading equipment condition but has not reached a concern of imminent failure; and
- Mobile substation planning – Includes assessing and maintaining the Company's mobile substation fleet based on historical project usage and the purchase of new mobile substations to replace those which have become uneconomical to repair.

Q. Does the Company consider non-wire alternatives in the LVD Substations Reliability sub-program?

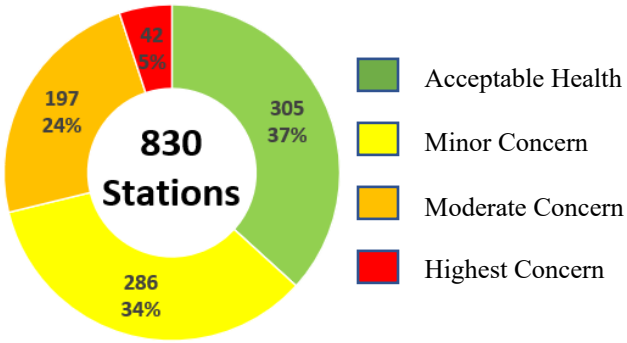
A. Not presently. Non-wire alternatives are not mature enough to adequately address the specific reliability issues that are the focus of this sub-program. As discussed by Company witness Kelly, the Company is intending to undertake an expediated pilot process to better understand how non-wire solutions ("NWS") can be utilized for reliability.

Q. How are the projected LVD Substation Reliability expenditures aligned with the Reliability Roadmap?

A. Figure 37 below, taken from the Reliability Roadmap, shows that a majority of LVD substations have at least some concerns in the Company's assessment of their asset health. Of the total population of LVD substations, 5% are a high priority for component repair or replacement and another 24% have a moderate level of risk. As stated in the Reliability

Roadmap, the Company plans to address these asset risks through a comprehensive plan to replace all components that are beyond end-of-life, including building and rebuilding substations, a plan which will result in two fewer LVD substation outages per year. Because LVD substation outages can impact a large number of customers, this will provide a meaningful reliability benefit. As shown in the Reliability Roadmap, this effort involves a ramp-up in LVD substation investment in both this sub-program and the LVD Substations Rehabilitation sub-program.

FIGURE 37
LVD SUBSTATION HEALTH



Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Substations Reliability sub-program?

A. The Company is projecting LVD Substations Reliability capital expenditures of $48,504,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 9, column (k), and $42,911,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 9, column (l). The Company's historical actual spending in the LVD Substations Reliability sub-program, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 9.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as shown in Figure 38 below.

FIGURE 38
LVD SUBSTATION RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
New or rebuilt substations	$28,200,000	17	$18,990,000	12
Mobile substations	$3,350,000	3	$8,993,000	2
Animal mitigation	$1,372,000	13	$1,950,000	14
Regulator replacements	$300,000	4	$450,000	6
Transformer replacements	$9,877,000	9	$7,714,000	5
DSCADA Projects	$5,405,000	15	$4,814,000	11
Total	**$48,504,000**	**61**	**$42,911,000**	**50**

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Substations Reliability sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-109 (MLH-3), page 44, and for the test year, listed in Exhibit A-110 (MLH-4), page 4. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the location and benefits of the projects.

Q. Are there any projects that span multiple years?

A. Yes, the Angell, Buckeye, Edgewood, Harmon Road, Houghton Lake, Iargo, Lower Lake, Prescott, Pullman, Waldron, Westphalia, Mobile 26, Mobile 29, Belknap, Broadmoor TB3, Broadmoor TB4, Lagrave, Manton, and Walnut projects, listed for the bridge period in

Exhibit A-109 (MLH-3), page 4, and for the test year, listed in Exhibit A-110 (MLH-4), page 4, will span multiple years due to ROW acquisition, transformer purchase order milestone payments, mobile substation purchase order milestone payments, and construction scheduling.

Q. What benefits will customers realize through the Company completing work in the LVD Substations Reliability sub-program?

A. Customer benefits in this sub-program can be categorized as reducing customer-outage-minutes or as service quality. Replacement of equipment decreases the likelihood of failure, resulting in fewer minutes per year of outage on average. Since 2012, when the Company increased animal mitigation installations at LVD substations, approximately 92% of substations equipped with the present substation animal mitigation standard have experienced no animal-caused outages since the installation was complete.

As discussed above, DSCADA has been transferred to this sub-program, and the control and data-gathering capability of DSCADA lets the Company obtain grid data that is analyzed to make decisions on what field devices need adjustments to optimize performance. Expanding DSCADA broadens the customer base that can benefit from improved customer reliability and reduced outage durations. By adding substation communications, the benefits associated with volt-var optimization ("VVO"), conservation voltage reduction ("CVR"), distributed energy resource ("DER") integration, automation transfer recloser ("ATR") loops, and voltage regulator controllers will benefit more customers. DSCADA reliability benefits are driven by reduced outage response time and faster restoration via remote operations.

Overall, the benefits for bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibit A-109 (MLH-3), page 4, and for the test year, listed in Exhibit A-110 (MLH-4), page 4. Types of benefits identified on the exhibits, and summarized in Figure 39, include:

- Customer-outage-minutes avoided – as defined previously, this is the expected reduction in the amount of outage time a group of customers would experience once the project is complete; and
- Service Quality – quantifies the number of customers benefiting from a project to improve the voltage to ensure that equipment operates properly as designed, keeping service point voltages within the ranges customers expect.

FIGURE 39
LVD SUBSTATIONS RELIABILITY BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	32,073,276	28,931,280
Service Quality; number of customers	2,471	2,825

Q. Are there customer reliability benefits from mobile substation purchases?

A. Yes. Mobile substations are purchased to support planned substation projects, planned lines projects, imminent failure concerns before customer outages occur, and unplanned failures to restore service to customers. Accordingly, it is difficult to predict where and when each mobile substation will be used to calculate the specific benefits.

Q. Please explain the historical year-over-year variation in spending in this sub-program.

A. In 2021, spending increased as the Company invested in 50 animal mitigation projects and seven transformer replacements. In 2022, the Company invested in four substation rebuilds, 31 animal mitigation projects, and three transformer replacements. In 2024, spending increased as the Company moved three work items to the LVD Substation Reliability sub-program from other sub-programs, as discussed above.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Average unit cost is not a good measure to predict the cost of an individual project in the new or existing substation rebuilds, animal mitigation, and transformer replacement investment categories due to specific work scopes needed for each project. New substation costs can vary based on the substation design, electrical capacity required, site conditions, etc. Substation rebuild costs can vary based on whether a full rebuild or a partial rebuild is required and whether load transfers to an adjacent substation can be utilized or if a mobile substation is required to maintain electrical service during the rebuild. Animal mitigation costs can vary based on the substation physical size and whether full mitigation or partial mitigation measures are required. Transformer replacement costs can vary based on the electrical capacity and voltages of the replacement transformer and whether load transfers to an adjacent substation can be utilized or if a mobile substation is required to maintain electrical service during the replacement. The average unit cost does reflect the expected spend per project for the regulator replacement investment category.

e) <u>LVD Substations Rehabilitation</u>

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Substations Rehabilitation sub-program.

A. The LVD Substations Rehabilitation sub-program includes capital repair or replacement of LVD substation equipment that has not actually failed but has been assessed to be at imminent risk of failure, projects to address code violations, and projects to replace obsolete equipment. Obsolete equipment includes reclosers, breakers, fuses, regulators, lightning

arresters, and switches that can no longer be purchased from manufacturers, have depleting inventory, and replacement parts can no longer be purchased.

Q. What are the inputs used to determine what equipment may be in an imminent failure status?

A. Imminent failures are identified by monitoring and tracking LVD substation equipment and components using various means of analysis such as dissolved gas analysis ("DGA") and infrared data. These analyses help to identify specific locations to target corrective action based on probability of an unplanned event, and to prioritize projects that will deliver the greatest reliability impact based on specific metrics (e.g. SAIDI and SAIFI). Proactively replacing deteriorated equipment that is deemed as an imminent failure in advance of an actual equipment failure is more economical as it typically avoids customer outages and costly overtime. Some imminent failures are identified through monthly visual patrols performed by the Company's Substation Operations group and are replaced through this program prior to failure. The cadence of the LVD substation equipment evaluation and inspection is found in Figure 40.

FIGURE 40
LVD SUBSTATION INSPECTION CADENCE

Inspection Task	Cadence	Actions Taken
All Station Components	Bi-Monthly	Visual inspection Routine patrol inspections
Entire Substation	Bi-Annually	Infrared inspection of entire substation
Protective Relays and Communication Systems	Dependent on relay model & failure history	Maintenance & testing performed
Station Batteries	Monthly	Voltage check
	Annually	Equalization
	Annually	Specific gravity reading
	4 Years*	Complete inspection
Power Transformers	Bi-Monthly	Visual inspection (including fans and pumps)
	Annually	Total combustible gas test (follow-up dissolved gas analysis tests, if warranted)
	Annually	Diagnostic Dissolved Gas Analysis of Load Tap Changer Oil (Transformers with Load Tap Changers Only)
	Annually	Diagnostic Dissolved Gas Analysis of mid-20th century vintage Allis Chalmers Transformers
	Bi-Annually	Diagnostic Dissolved Gas Analysis of Transformer Main Tank Oil (Transformers with Load Tap Changers Only)
	6 years**	Diagnostic dissolved gas analysis of transformer oil (Non-Load Tap Changer Transformers)
Motor Operated Air Break Switches (MOABS)	Annually	Test Operated (decoupled)
	4 Years**	Battery replacement
Single Phase Regulators	9 Years***	Limited program of dissolved gas analysis

*Or periodically as needed
**Or sooner if determined by combustible gas tests or high gas levels in previous tests
***Started in 2014

Q. Do any other operating organizations or departments provide input into this sub-program?

A. Yes. Input from operating organizations and other departments inform the substation planning engineers with operational concerns, system constraints, and regulatory changes that may trigger a need for replacement of obsolete equipment, replacement of imminent equipment failure, or substation modifications to comply with new regulatory requirements.

Q. What investment categories are included in the LVD Substations Rehabilitation sub-program?

A. The LVD Substations Rehabilitation sub-program includes:

(i) Allis Chalmers substation transformer replacements, and

(ii) Equipment replacement and regulatory-related projects, which include end-of-life condition substation rebuilds, equipment at risk of imminent failure, addressing new regulatory requirements, and replacement of obsolete equipment such as reclosers, breakers, fuses, regulators, lightning arresters, and switches.

Q. Please describe the Allis Chalmers substation transformer replacement investment category.

A. Allis Chalmers mid-20th century vintage substation power transformers were produced with a design deficiency associated with the top clamping structure of the transformer windings. The key purpose of the clamping structure is to prevent winding movement. This deficiency results in an inherent weakness of the transformer to withstand the forces accompanying certain magnitude low side faults. Winding movement typically results in electrical shorts and arcing, which lead to excessive heating, creation of combustible gasses, and eventual failure of the transformer.

Q. How many of these Allis Chalmers substation transformers are in-service at LVD substations and what has the Company's recent experience been with these transformers?

A. Going into 2025, the Company will have 31 of these Allis Chalmers units in-service in their original design, and another six rewound units in-service that are considered at risk of developing the condition, for a total of 37 units at its LVD substations. From 2014 through 2018, approximately 28% of the substation transformer failures had been from this vintage and manufacturer, but increased monitoring and replacement resulted in no transformer failures from this vintage and manufacturer from 2019 through 2024.

Q. What has been the Company's recent performance in replacing Allis Chalmers substation transformers?

A. The Company has been replacing Allis Chalmers transformers as follows:

	2017	2018	2019	2020	2021	2022	2023	2024
Allis Chalmers Transformer Replacements	9	10	15	6	19	7	5	3

Q. Please explain the equipment replacement and regulatory-related projects investment category.

A. When a substation is at the end of its useful life and experiences substantial deterioration – becoming unsafe, no longer able to reliably operate, or some other issue – the Company may elect to rebuild the substation. However, the Company is not planning any end-of-life condition substation rebuilds in the test year. For regulatory-related projects, the Company is planning projects related to working space, which bring substations into compliance with NESC Rule 125, section A, titled "Working space about electric equipment: Working Space (600 Volts or Less)." When the Company was working to upgrade its telecommunications

at its LVD substations in the late 2010s, it discovered that some of the substations did not meet the NESC working space requirements and began a process of addressing all of these working space issues by 2028. The Company has completed 42 of the 66 identified capital projects at its LVD substations and plans to complete the remaining 24 capital projects by 2028.

Q. How does the Company treat obsolete equipment in this sub-program?

A. When specific types of equipment can no longer be purchased from manufacturers, replacement parts can no longer be purchased, and inventory levels are depleting, equipment is classified by the Company as obsolete. Targeted replacements are implemented because new equipment may not fit into the same location without structural substation modifications due to physical size, mounting requirements, and electrical clearance requirements.

Q. Are there any projects that span multiple years?

A. Yes, the Ballenger, Bellaire, Cooper, Crofton, Fountain, Gladwin, GMI, Godfrey, Golden, Hart, Lennon Road, Lyons, Mayfair, Nestrom, Ottawa Beach, Saginaw Street, Stanton, Dutton, Fairbanks, Howard City, Hudsonville, Lake Shore, Mancelona, New Richmond, Nineteen Mile Rd, Port Calcite, and Steelcase projects, listed in Exhibits A-108 (MLH-2), page 5, and A-110 (MLH-4), page 5, will span multiple years due to transformer purchase order milestone payments and construction scheduling.

Q. What benefits will customers realize through the Company completing work, in the LVD Substations Rehabilitation sub-program?

A. This sub-program works to address areas in LVD substations where code violations are present, or where failures, and corresponding outages and customer interruptions, are

particularly likely. Addressing degrading equipment reduces the likelihood of failure, resulting in fewer minutes per year of outages on average. The benefits for the bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-108 (MLH-2), page 5, and A-110 (MLH-4), page 5. The types of benefits identified on the exhibits, and summarized in Figure 41, include:

FIGURE 41
LVD SUBSTATIONS REHABILITATION BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	52,145,000	38,240,000
Regulatory Compliance projects	13	6

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Substations Rehabilitation sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-109 (MLH-3), page 5, and for the test year, listed in Exhibit A-110 (MLH-4), page 5. These exhibits also identify the location and benefits of the projects.

Q. Are there circumstances in which Allis Chalmers substation transformer replacements could be reprioritized?

A. For several years occurring after the test year, the Company plans to replace the 20 remaining Allis Chalmers transformers at LVD substations. The Company prioritizes which transformers to replace each year based on DGA testing results and infrared data. While the Company has identified the projects for the bridge period and the test year, the Company could re-prioritize and target different transformers if testing results indicated that re-prioritization is warranted to reduce the probability of transformer failures across the system.

Q. Why is the Company requesting approval of these expenditures in this proceeding?

A. The projects in the LVD Substations Rehabilitation sub-program replace degrading and obsolete equipment with a high risk of causing service interruptions or reducing service quality, resolve unsafe substation conditions, and resolve conditions that could degrade substation reliability. Delaying replacement of this equipment is highly likely to lead to unplanned outages, interrupting service to customers.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Substations Rehabilitation sub-program?

A. The Company is projecting LVD Substations Rehabilitation capital expenditures of $40,895,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 16, column (k), and $31,147,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 16, column (l). The Company's historical actual spending in the LVD Substations Rehabilitation sub-program, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 16.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The LVD Substations Rehabilitation sub-program is an important part of the Company's plan to address deteriorating assets and maintain reliability. The bridge period and test year spending amounts were determined based on the amount of investment needed to complete the projects identified.

By investing at the projected spending level in the bridge period, the Company will be able to: (i) complete 14 projects to replace Allis Chalmers substation transformers; (ii) complete four projects to replace non-Allis Chalmers substation transformers;

(iii) complete 16 purchase order milestone payments for transformer replacements beyond the bridge period; (iv) complete 13 projects to address working clearance code issues; and (v) complete five projects to replace equipment.

By investing at the projected spending level in the test year, the Company will be able to: (i) complete three projects to replace Allis Chalmers substation transformers; (ii) complete two projects to replace non-Allis Chalmers substation transformers; (iii) complete 15 purchase order milestone payments for transformer replacements beyond the test year; (iv) complete six projects to address working clearance code issues; and (v) complete four projects to replace equipment. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. This level of spending is adequate to meet the sub-program goals and regulatory deadlines while remaining agile to address imminent failure concerns.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the investment categories.

A. The Company is projecting units completed and capital expenditures in the bridge period and the test year for each investment category as shown in Figure 42 below.

FIGURE 42
LVD SUBSTATIONS REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Allis Chalmers substation transformer replacements	$22,465,000	26	$14,548,000	18
Equipment replacement and regulatory	$18,430,000	26	$16,599,000	13
Total	**$40,895,000**	**52**	**$31,147,000**	**31**

Q. How are the projected LVD Substations Rehabilitation expenditures aligned with the Reliability Roadmap?

A. As previously discussed in the section of my testimony on the LVD Substations Reliability sub-program, the Reliability Roadmap includes an assessment of LVD substation asset health and presents an increased investment plan to address assets at risk. The Company is increasing its investment in both LVD substations-related sub-programs in response to the plan laid out in the Reliability Roadmap.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No, the average unit cost does not accurately reflect the expected spend due to specific work scopes needed for each project and the variance in costs depending on the individual project scope.

f) <u>Metro Reliability</u>

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the Metro Reliability sub-program.

A. The Metro Reliability sub-program ensures the long-term safe and reliable operation of the Company's Metro systems with investments to install and upgrade the civil and electrical assets that distribute electricity in those downtown cores. Metro Reliability investments fall into three categories:

(i) obsolete or needed civil assets;

(ii) obsolete or needed electrical assets; and

(iii) dead fronting equipment.

Q. How does the Company address projects that require modified civil infrastructure?

A. For projects that require new or modified civil infrastructure, the Company releases the scope to a contracted civil engineering firm, who creates a feasibility study for a civil infrastructure path. The feasibility study provides several options for possible routes and estimated construction costs for those options. The Company's metro engineering planner reviews the feasibility study with operations representatives to determine ease of construction and impact to future electric operations. The metro engineering planner notifies the civil engineering firm, who will prepare a design based on the selected option. The metro engineering planner will prepare an electrical design, cable pulling schedule, and electrical bill of materials. The civil engineering firm delivers the design and any documents needed to obtain a permit to perform work in the ROW from the Michigan Department of Transportation or the municipality, including a detailed traffic control plan.

Q. How are Metro Reliability expenditures aligned with the Reliability Roadmap?

A. Planned Metro Reliability expenditures in this case are aligned with those presented in the Reliability Roadmap, and projects are also identified based on the process outlined in the Reliability Roadmap, whereby Metro planning and design engineers assess multiple components of each vault, which produces a vault health score.

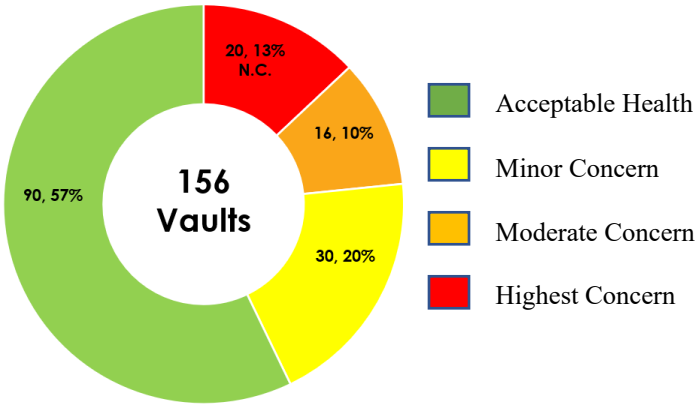
The Company reviews Metro Reliability projects during an annual planning cycle each year. While the Company continuously monitors the reliability of the Metro system, this annual review helps determine which line segments and components need to be addressed each year, as some projects may be large enough to span multiple years. Additionally, the Company determines which remediation strategy to use. Due to the lengthy customer interruptions that a Metro outage can cause, these projects are proactive

to prevent an outage from occurring and not due to a previous interruption. Inputs the Company uses in its Metro reliability assessment include:

- Metro condition is assessed based on safety and ability to operate existing equipment;
- Projects are prioritized based on reliability benefits to each customer category, with highest priority for critical customers, followed by large residential customers and then other commercial and residential customers; and
- When the Company receives external requests, particularly for Metro New Business and Metro Asset Relocations, the Company may also perform Metro Reliability work at the same time to gain efficiencies.

The Company's current Metro asset health results are summarized in Figure 43 below.

FIGURE 43
SUMMARY OF METRO HEALTH VAULT ASSESSMENT RESULTS



Q. What types of work does the Company complete as part of obsolete electrical asset replacement projects?

A. The Company replaces functionally obsolete equipment, including:

(i) Deteriorated SF6 insulated switches with new SF6 insulated switches;

(ii) Polychlorinated biphenyl ("PCB") oil-insulated voltage transformers with non-PCB transformers and dead front busing well inserts; and

(iii) Impregnated Paper Lead Covered and Varnished Cambric Lead Covered cable with crosslinked tree retardant polymer insulated cables.

Q. What types of work does the Company complete as part of dead fronting equipment?

A. Dead fronting equipment enhances worker safety by eliminating exposed energized components in Metro assets. The Company does this by replacing:

(i) Live-front, vault-style transformers and fusing with molded vacuum interrupters;

(ii) Encapsulated transformer bushings (fuses and elbow type) and live secondary buss with guarded load centers;

(iii) High rise live-front transformers; and

(iv) Padmount live-front transformers, including transclosures.

Q. What benefits will customers realize through the Company completing work, in the Metro Reliability sub-program?

A. Metro Reliability investments minimize potential adverse impacts on customers by improving overall reliability and operational safety. Civil projects share the benefits with the corresponding electrical project. Benefits are fully realized when the electrical portion is completed. Furthermore, investments in the Metro Reliability sub-program can reduce overall cost associated with emergent response in the Metro Demand Failures sub-program. Replacement of equipment decreases the likelihood of failure, resulting in fewer minutes per year of outage on average. These benefits for the bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-109 (MLH-3), page 6, and A-110 (MLH-4), page 6. Types of benefits identified in the exhibits, and summarized in Figure 44, include:

- Customer-outage-minutes avoided – as defined previously, this is the expected reduction in the amount of outage time a group of customers would experience in a year once the project is complete; and
- Worker Safety – create safer work conditions within metro vaults.

FIGURE 44
METRO RELIABILITY BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	24,365	127,734
Worker Safety projects	2	2

Q. What is an example of a recently completed Metro Reliability project that created safer work conditions?

A. The Company recently completed a vault dead fronting project at the JC Penney Vault in Battle Creek. The vault previously had obsolete electrical equipment and presented a worker safety concern to energized and exposed electrical components while working within the vault. In addition, parts of the vault roof and walls required some concrete rehabilitation repairs. The electrical equipment was updated to mitigate all exposed electrical component hazards, and the civil repairs were completed and sealed with a concrete sealant, extending the life of the structure.

FIGURE 45
VAULT BEFORE AND AFTER RELIABILITY PROJECT



Q. Are there customer reliability benefits expected from mobile vaults?

A. Yes. The Company is planning to receive its two mobile vaults in 2025. Mobile Vaults plan to be used as a tool to facilitate more dead-fronting equipment projects, and to decrease the operational response time to unplanned vault transformer outages. These mobile vaults will build on the Company's successful use of mobile substations and reduce costs through the avoidance of custom, temporary above-grade installations or use of on-site generation. Mobile vaults are proposed to support planned Metro projects and unplanned failures to restore service to customers. Accordingly, it is difficult to predict where and when each mobile vault will be used to calculate the specific benefits. What is known is that there is, on average, $12,800 O&M savings per vault per week based on the present cost of generator rental, diesel fuel, and maintenance costs. The Company expects to realize approximately $400,000 in O&M savings per year based on anticipated usage.

Q. Please describe the types of risks encountered as part of this sub-program.

A. Risks that may be encountered during construction of Metro Reliability projects that can impact cost include:

- Encountering crushed conduit while attempting to replace cable. Conduit can be crushed as a result of heavy loaded objects above the ground or the fiberglass becoming brittle as a result of exposure to soil conditions;
- Increased costs associated with temporary transformation and items required to temporarily connect customers to this equipment. This is similar to the use of a mobile substation to allow for safe maintenance or construction work on de-energized equipment. However, instead of being on wheels, the set of padmounted equipment must be temporarily constructed at grade level and fenced to guard from the public; and
- Potential fluctuation in contractor costs. Contractor costs can fluctuate between projects based on the bids received. This is based on the amount of work that the contractor already has secured and the cost for the contractor to add this to their work plan (additional or mobilizing resources).

Q. Please identify the projects that will be accomplished with the requested spending level in the Metro Reliability sub-program.

A. The Company has identified projects for the bridge period, which are listed in Exhibit A-109 (MLH-3), page 6, and for the test year, which are listed in Exhibit A-110 (MLH-4), page 6. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the location and benefits of the projects.

Q. Why is the Company requesting approval of these expenditures in this proceeding?

A. The identified projects will benefit customers by addressing historical outages and ensuring the long-term safe and reliable operation of the LVD metro system. These benefits will be harvested through the replacement of degrading equipment before further service interruptions occur, and by updating Metro vaults and manholes to modern design standards and electrical clearances to improve worker safety.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Metro Reliability sub-program?

A. The Company is projecting Metro Reliability capital expenditures of $5,329,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 13, column (k), and $3,998,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 13, column (l). These values are consistent with the five-year average spend in this sub-program of $4,811,000 as shown in Exhibit A-113 (MPK-3), line 13, column (h). The Company's historical actual spending in the Metro Reliability sub-program, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 13.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The bridge period and test year spending amounts were determined based on the amount of investment needed to complete the projects identified. The Company has been experiencing an increase in both incidents and customer-outage-minutes in the Metro systems in recent years, as shown in Figure 46. By investing at the requested spending levels, the Company has been able to repair or replace Metro assets that have been identified as contributing to outages to downtown customers.

FIGURE 46
METRO SYSTEMS ANNUAL OUTAGE HISTORY

	2020	**2021**	**2022**	**2023**	**2024**
Number of incidents	23	26	17	26	31
Total customer-outage-minutes	457,422	550,414	341,144	344,979	903,757

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the three investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and the test year for each investment category as identified in Figure 47 below.

FIGURE 47
METRO RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	**Bridge Period Capital**	**Bridge Period # of Units**	**Test Year Capital**	**Test Year # of Units**
Obsolete or Needed Civil Assets	$1, 000,000	1	$2,300,000	2
Obsolete or Needed Electrical Assets	$704,000	2	$1,098,000	3
Dead-Fronting Equipment	$1,125,000	2	$600,000	2
New Technologies (Mobile Vaults)	$2,000,000	2		--
Total	**$5,329,000**	**7**	**$3,998,000**	**7**

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Spending in this sub-program may vary from year to year, because the Metro systems have a smaller number of projects than other Reliability sub-programs, and those Metro Reliability projects can vary significantly in size and cost. In 2021, the Company completed an above average amount of Metro Reliability projects, including a large project to replace obsolete lead primary cables with polymer insulated primary cables in Grand Rapids, civil infrastructure projects in Kalamazoo and Saginaw, and a vault dead fronting project in Battle Creek.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Average unit cost is not a good measure of spend to predict the cost of an individual project in this sub-program. There is a wide variance of scale and scope among the work required ranging from $250,000 to dead front a small vault to over $1,000,000 for a civil replacement project.

g) <u>Metro Rehabilitation</u>

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the Metro Rehabilitation sub-program.

A. The Metro Rehabilitation sub-program addresses assets on the Company's Metro systems that have been identified as being at a high risk of imminent failure, such that replacement is justified based on potential risks to public, employee, or contractor safety, or to maintain the reliability of the Metro systems. The Metro Rehabilitation sub-program consists of two investment categories: crushed duct replacements and vault or manhole rehabilitation.

Q. Please explain crushed duct replacements.

A. When an existing duct bank has been crushed or is deteriorated, it is replaced with a new concrete-encased duct bank. New cable must also be run through the new duct bank to replace the damaged cable.

Q. Please explain vault or manhole rehabilitation.

A. Vaults or manholes require replacement of the entire structure—or portions of the structure, such as an existing roof—that is damaged or deteriorated. Damaged or deteriorated subsurface structures create safety hazards to the public passing over them and employees entering the structure.

Q. How are the projected Metro Rehabilitation expenditures aligned with the Reliability Roadmap?

A. Similar to Metro Reliability, planned Metro Rehabilitation activities are tied to addressing asset health concerns in Metro assets, and expenditures in this case are aligned with those presented in the Reliability Roadmap. Projects are identified based on the process outlined in the Reliability Roadmap as well.

Q. Did the Company consider any alternative approaches to project selection that could help achieve the Reliability Roadmap objectives?

A. Yes. Alternatives are considered for each project in the Metro Rehabilitation sub-program; however, viable options are often limited due to the need to maintain service in the dense downtown districts. One alternative often evaluated is whether a given vault can be eliminated and replaced with an at-grade transformer installation. This alternative is wholly dependent upon suitable space to install the at-grade facilities, which often is not available in the downtown areas. Alternative locations for the new facilities and rerouting of electrical

cables through already existing civil infrastructure are also considered. Each project is selected based upon its effectiveness at solving the identified problem, the cost of the project, and the relative benefits.

Q. What benefits will customers realize through the Company completing work in the Metro Rehabilitation sub-program?

A. Upgrading and replacing degraded components in the Metro system allows the Company to maintain a redundant system in the downtown areas of cities, providing a reliability benefit. This benefit directly impacts customers including courthouses, jails, municipal offices, police, and fire departments, as well as many businesses and residents. Replacement of equipment decreases the likelihood of failure, resulting in fewer minutes per year of outage on average. Additionally, a Metro system in good condition allows employees and contractors to work in a safe environment and supports public safety. Investing in the Metro system to alleviate failure conditions allows customers not to be single sourced as the Company isolates manholes and vaults for repair. These benefits for bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-109 (MLH-3), page 7, and A-110 (MLH-4), page 7. Civil projects share benefits with the corresponding electrical project; benefits are fully realized when the electrical portion is completed. Types of benefits identified on the exhibits and summarized in Figure 48 include customer-outage-minutes avoided; as defined previously, this is the expected reduction in the amount of outage time a group of customers would experience in a year once the project is complete.

FIGURE 48
METRO REHABILITATION BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	77,680	153,550

Q. Please identify the projects that will be accomplished with the requested spending level in the Metro Rehabilitation sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-109 (MLH-3), page 7, and for the test year, listed in Exhibit A-110 (MLH-4), page 7. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the location and benefits of the projects.

Q. Why is the Company requesting approval of these expenditures in this proceeding?

A. The Metro Rehabilitation sub-program is a key component of the Company's plan to improve overall reliability. This sub-program addresses those components of the Metro asset base that are most vulnerable to failure and corresponding interruptions to customers. By investing at the requested spending level, the Company will be able to repair or replace Metro assets identified as being at a high risk of imminent failure.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Metro Rehabilitation sub-program?

A. The Company is projecting Metro Rehabilitation capital expenditures of $7,987,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 18, column (k), and $5,993,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 18, column (l). The Company's historical actual spending in the Metro Rehabilitation sub-program, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 18. This sub-program was created in 2020; there was no spending in 2019.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The Company's projected bridge period and test year spending amount was determined based on the amount of investment needed to complete the projects identified. The Company is maintaining spending levels for the bridge period and test year to continue to address rehabilitation projects.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the two investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and the test year for each investment category as identified in Figure 49.

FIGURE 49
METRO REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Crushed duct replacements	$1,300,000	2	$4,993,000	2
Vault or manhole rehabilitation	$6,687,000	8	$1,000,000	2
Total	**$7, 987,000**	**9**	**$5,993,000**	**4**

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Average unit cost is not a good measure of spending to predict the cost of an individual project in this sub-program. There is a wide variance among work required, ranging from $200,000 for small vault projects to as high as $1,850,000 for crushed duct and vault rehabilitation projects.

h) System Protection

Q. What is the purpose of the HVD protective system?

A. The distribution system experiences electrical faults such as wire downs, lightning strikes, failed equipment, etc. When this happens, the purpose of a protective system is to de-energize as quickly as possible the minimum amount of the electric network that has experienced a fault, to isolate the fault, and mitigate damage to other equipment.

Q. Do protective systems experience failures?

A. Yes, protection systems have two modes of failure. The first is an *incorrect operation*, which is when a protective device operates when it should not. This failure mode can cause unnecessary customer outages, and in severe cases can lead to cascading outages that result in widespread blackouts. Protection system failures have played a part in many of the largest blackouts in history, including a protective system failure on November 9, 1965, that caused the "Northeast Blackout of 1965," interrupting service to 30 million people; and a protective system failure on February 26, 2008, in Florida, resulting in 4,300 MW of generation going off-line, and a loss of 3,560 MW of customer load, and a fine to Florida Power and Light by the Federal Energy Regulatory Commission of $25 million. Protection system failures also contributed to the largest United States blackout in history on August 14, 2003. These failures resulted in the creation of dozens of new reliability standards by the North American Electric Reliability Corporation related to the operation and maintenance of protective systems.

The second failure mode is when a protection system *does not correctly de-energize an electrical fault*. Failure of a protection system to de-energize a fault can lead to more customers interrupted than are necessary, equipment damage as lines and/or transformers

burn up, environmental hazards due to ruptured transformers, and public safety hazards due to fires, shrapnel from exploding equipment, and electric shocks due to uncleared electrical faults.

Q. Do failures detrimentally impact customers?

A. Yes. Since failure of a protection system during a fault can result in extensive damage to the electric network, it can take much longer to restore service to customers while additional equipment is repaired or replaced. Due to these risks, protection systems are a critical function of the electric network since they backstop against extensive outages and public safety hazards when other components of the electric network fail. When protective systems fail, this can result in the outage impacting a larger area than is necessary to isolate the fault. This makes it more difficult to locate the problem on the electric network and extends the time needed for restoration.

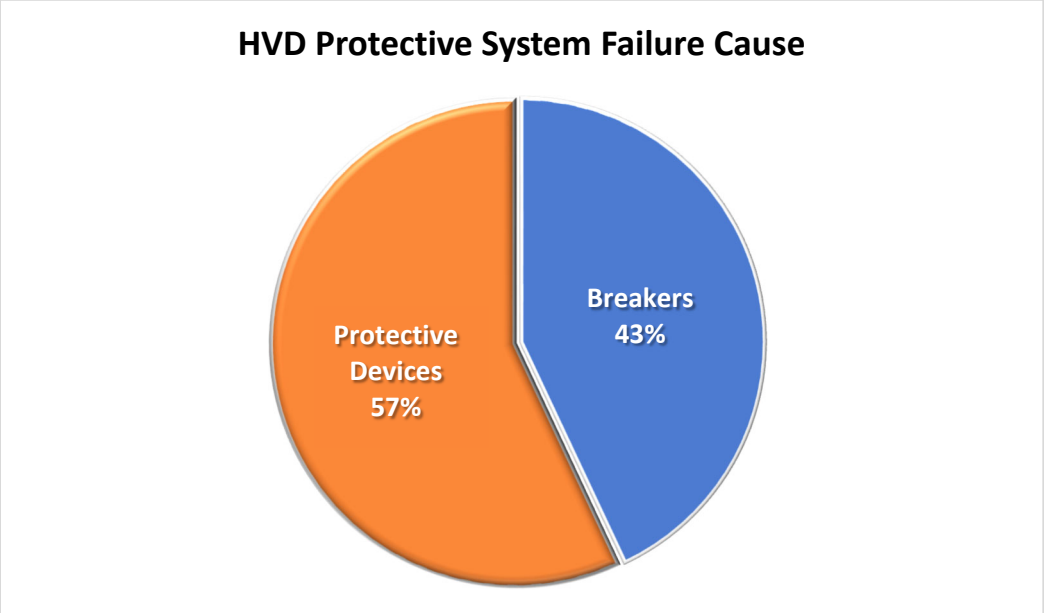
Q. What is the present state of the Company's HVD protective system?

A. The Company has determined design life for protective relays based on vendor recommendations, industry best practices as documented by the Institute of Electrical and Electronics Engineers ("IEEE") Power System Relaying Committee, and Company experience with failure of specific relay types. Approximately 17% of the protective relay population is older than the designated design life; this increases to 34% for the population of electromechanical ("EM") relays. As EM relays age, they are more frequently out of settings tolerance, which can cause interrupting devices (like circuit breakers, circuit switchers, etc.) to open when they do not need to, or not open when they should, leading to interruptions and possible damage to equipment. More frequent field testing and calibration is required to assure proper performance.

Q. How will replacing EM relays with digital relays support customer reliability?

A. Digital relays do not lose setting tolerance like EM relays and require significantly less maintenance. Historic EM relays require maintenance twice as often to keep within their setting tolerance. Replacing historic EM relays with digital relays not only reduces the risk of failure, but also lowers O&M expenses associated with relay testing. Over the past three years, relays contributed to approximately 57% of the failures of an HVD protective system to clear a fault and restore un-faulted HVD equipment correctly (see Figure 50).

FIGURE 50
HVD PROTECTIVE SYSTEM FAILURE TO CLEAR AND RESTORE BY CAUSE. 2022-2024



Q. Why is the Company requesting approval for these projects in this proceeding?

A. The relays replaced under this program are obsolete and, in most cases, no longer available, so quick like-for-like replacement is not an option. Replacement requires building new relay panels, which take several months to design, build, and install. Proactively replacing these panels reduces the risk of several months of outages when a relay failure occurs. Further, projections show an increasingly large number of obsolete relays reaching end-of-life (with an increased risk of failing) over the next 10 years as described in the

Reliability Roadmap. A consistent level of investment to replace a smaller number of relays each year will avoid a mass failure of relays in the future that would strain resources to replace all at once.

Q. What projects, activities, and other types of work will be funded by expenditures in the System Protection sub-program, to help achieve these longer-term reliability objectives?

A. The System Protection sub-program replaces obsolete relays with new digital devices that have fault monitoring capabilities to improve reliability and offset future O&M costs. This sub-program targets relays that are reaching end of life.

Q. What benefits will customers realize through the Company completing work in the System Protection sub-program?

A. As noted above and discussed in the Reliability Roadmap, protection systems are critical to minimizing damage and protecting public safety as the final backstop when other components of the electric network fail. Replacing end-of-life HVD relays before they fail helps mitigate the expanded outage risk to customers and the hazard to the public. The projected expenditures provide for the level of investments necessary in the System Protection sub-program to address obsolete, poor performing relays to ensure proper operability of the HVD network and minimize the risk of outages to customers.

Q. Please provide additional information on the benefit to safety and how the investment will benefit customers.

A. If a protection system fails to de-energize a fault, it can result in safety hazards. For example, a failed protection system can cause a conductor to remain energized on the ground, posing an electrocution risk. A fault that is not cleared correctly by the protection

system could also cause a fire, and/or an explosion of electric equipment like transformers. An extended fault can also result in an environmental spill of oil. Investment in the HVD protective system is paramount to ensuring the public is kept safe from the hazards of the HVD electrical system.

Q. How does the System Protection sub-program impact reliability?

A. While safety is a key priority of the HVD protective system, the protective system also directly impacts reliability. As noted above, there are two failure modes for protective systems. When protective systems fail by operating when they should not, this can cause unnecessary outages to customers due to tripping portions of the electric system that are not experiencing a fault. When protective systems fail by not operating when they should, this creates a need to interrupt more of the electric system than is necessary to clear the fault and can interrupt more customers than necessary. The latter scenario can also cause additional damage, such as transformer fires or damaging line conductors due to the extended fault clearing times, and takes longer to repair and restore customers due to the additional damage and larger area of outage.

The System Protection sub-program also plays a role in reducing the CAIDI, which in turn reduces SAIDI. New digital relays contain oscillographic recording functions that allow for evaluation of system conditions in real time, allowing engineers to remotely interrogate the system to locate faults more quickly and with more precision. This allows repair crews to find the problem and address it more quickly, restoring customers faster, which reduces CAIDI.

Q. Are there any other benefits to replacing EM relays with digital ones?

A. Experience has shown that digital relays can be tested once every five years instead of once every four years for EM relays. The time spent to test and calibrate digital relays is 50% less than a comparable EM relay. One HVD relay project typically replaces six EM relays with two new digital relays. Considering these reductions, the Company estimates that a modern digital relay package requires 87% less O&M expense on average to maintain than a comparable EM unit.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, in the System Protection sub-program?

A. The Company is projecting System Protection capital expenditures of $6,768,000 in the bridge period and $4,098,000 in the test year, as shown in Figure 51 below.

FIGURE 51
SYSTEM PROTECTION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Category	Bridge Period Capital	Bridge Period Units	Test Year Capital	Test Year Units	Benefit
Relay Replacements	$6,768,000	61	$4,098,000	24	Safety, Reliability
Total	**$6,768,000**	**61**	**$4,098,000**	**24**	

Q. What is the basis for the Company's projected test year spending level in the System Protection sub-program?

A. The Company's projected System Protection investment in the test year closely aligned with the five-year average, which is shown in Exhibit A-113 (MPK-3), line 11. Based on the relay asset health model, spending at the five-year average level will reduce the quantity of installed relays beyond their design life to zero in seven years and sustain that level going forward from that point.

This level of investment will support 24 relay units at six sites in the test year. The specific costs for the test year projects were determined using unit costs based on past work order costs for replacement of like equipment, and further refined taking into consideration the complexity of the specific relay schemes as well as the need for replacement of control enclosures due to NESC working space requirements. The average unit costs for the test year are expected to be higher due to one project requiring a new control enclosure due to NESC working space requirements, and elevated costs to remediate asbestos relay panels at three sites.

Q. Please list any projects that make up the requested spending level in the System Protection sub-program for the bridge period and test year.

A. Projects for the System Protection sub-program are identified in Exhibit A-109 (MLH-3), page 8, and Exhibit A-110 (MLH-4), page 8.

Q. What has been the historical actual spending in the System Protection sub-program for the past five years?

A. The historical actual costs for the System Protection sub-program are shown in Figure 52 below.

FIGURE 52
SYSTEM PROTECTION HISTORIC SPENDING

2020	2021	2022	2023	2024	5-Year Average
$2,626,241	$2,620,111	$4,504,000	$4,386,998	$4,848,000	$3,797,000

Q. Please explain the year-over-year variation in spending in this sub-program.

A. In 2020 and 2021, the effects of the pandemic resulted in a decrease in the overall spending in this sub-program compared to earlier years as availability of construction resources and materials was challenged, so spending increased after that point to return to more normal

levels. Additionally, beyond 2021, spending has ramped up to mitigate the risk described above of relays in service beyond their design life as identified in the relay asset health model.

Q. What are the historical unit costs for the System Protection sub-program?

A. Historical unit costs are provided in Figure 53 below; note that some projects span multiple years:

FIGURE 53
SYSTEM PROTECTION UNIT COSTS

Investment Categories	2020	2021	2022	2023	2024
Locations	6	3	10	10	6
Total Relay Replacements	58	13	41	36	17
Cost per Location	$437,707	$873,366	$409,455	$409,455	$808,000
Cost per Relay Replacement	$45,280	$201,546	$109,854	$121,861	$285,176
5-Year Average Cost per Relay Replacement	**$115,061**				

Q. Please explain any variation in unit costs over time.

A. Costs per location can easily vary because each project at each given location can involve a different number of relay replacements. Additionally, some projects carry over from one year to the next; in these cases, dollars are spent throughout the project, but the unit is only counted once it is complete. This makes unit costs less consistent from year to year. For instance, the 2021 unit cost was relatively high because several units that began in 2021 did not complete until 2022, while most of the cost of those projects were incurred in 2021. The 2020 unit cost was relatively low because of the high unit count of projects carried over from 2019, where most of the costs for those projects were incurred in 2019. Similarly, the

2024 unit cost was high because many units started in 2024 will be completed and counted in 2025. Averaging the unit cost over the life of each project rather than by budget year brings a more consistent unit cost average of approximately $115,000 per relay replacement.

2. CAPACITY

a) HVD Lines and Substations Capacity

Q. What is the purpose of the HVD Lines and Substations Capacity sub-program?

A. The overall purpose of the Capacity Program is to ensure that the system can serve peak demand load, as discussed by Company witness Kelly in his direct testimony. The HVD Lines and Substations Capacity sub-program is specifically designed to:

- Ensure capacity needs on the HVD system in accordance with HVD planning criteria;
- Accommodate new interconnections to the HVD System;
- Improve functionality through standards, upgrades to protection, and operability of the system;
- Coordinate with transmission infrastructure additions; and
- Support ROW acquisition projects to support HVD Lines and HVD Substation projects in this sub-program as well as ROW acquisition needed to bring existing HVD Line and HVD Substation ROWs up to present standards.

Q. To what extent are HVD Lines and Substations Capacity sub-program investments "planned"?

A. Each Capacity sub-program consists primarily of investments that are proactive, in that they do not respond to an emergency. However, there are circumstances where projects may need to be pulled ahead or inserted into the plan, for example to avoid an overload caused by unexpected load growth, an unexpected request to coordinate with a Transmission project, or third-party generator interconnection requests.

Q. How does the HVD Lines and Substations Capacity sub-program align with the Reliability Roadmap?

A. This sub-program is aligned with the "HVD Load Growth and Interconnection" component of the Reliability Roadmap. Investments in this sub-program support the Company's goals of ensuring that the HVD system can serve electric peak demand, accommodate new interconnections, and ensure current standards to support improved functionality of the system.

Q. What benefits will customers realize through the Company completing work in the HVD Lines and Substations Capacity sub-program?

A. Because the HVD system is the backbone infrastructure of the electric distribution network, projects in this sub-program must be completed on an as-needed basis to serve customers and maintain the safety and overall reliability of the grid. This sub-program ensures that the HVD system has the capacity to accommodate potential changes to the load profiles needed for new and changing technologies such as electrical vehicles and other potential electric growth in the future due to emerging technologies. Although this sub-program is not specifically designed to address system deterioration, investments in this sub-program improve system reliability and safety, and prevent future overloads, which can trigger dangerous wire downs and equipment failures due to exceedance of equipment interrupting capability.

Q. What investment categories are included in the HVD Lines and Substations Capacity sub-program?

A. The investment categories are:

- Load Carrying Capabilities and Voltage Support

- New Interconnections
- Improved Functionality
- Coordination with Transmission
- ROW Procurement

Q. What projects are funded by the Load Carrying Capabilities and Voltage Support investment category?

A. The Load Carrying Capabilities and Voltage Support investment category contains projects that eliminate unacceptably low voltage, loadings above line and equipment ratings, and available short circuit above equipment interrupting capability. These capacity projects must be completed based on projected loading in power flow models to serve customers and maintain the safety and overall reliability of the grid. The Company studies the HVD system using power flow analysis to calculate the base power flow and voltages, and changes in power flow and voltages resulting from single outages for present and future versions of the HVD system. The HVD system model is updated annually, following summer peak loading and into the first quarter of the following year. The studies are performed in the second quarter each year, and projects are then developed to address identified projected issues before the issue occurs in subsequent years. SCADA information is also used to project future load on the HVD system. Through this process, HVD facilities are identified that would violate the HVD Planning criteria due to line or equipment overload, or due to unacceptably low voltage during base (normal) conditions at system peak load or during single (N-1 equipment out of service) outage conditions at 80% of system peak load. Outage conditions studied include single line, single transformer, single bus, and single generator outages. Also identified are interrupting devices where the available short circuit is

projected to exceed interrupting capability. The Company's plans to fix projected criteria violations are tested in the models to ensure they fulfill their designed purpose.

Q. How are projections of peak load developed?

A. Each year, after summer peak conditions, the Company revises its load forecast to reflect the most recent experience with customer peak usage. The load forecast is done at the system and circuit levels and represents the simultaneous usage of all downstream customers.

Q. How does the Company project loading on individual elements of the electric system?

A. For HVD elements, the Company's planning engineers allocate the system load to individual substation loads using SCADA data. The Company's planning engineers then use power flow modeling to identify loading on each element of the electric system. The power flow model simulates how power flows on the electric system, based on the fundamental laws of electricity. These models can identify loading on each element, compare it with the capacity of that element, and provide the Company's Planning Engineers with those instances where capacity is insufficient to meet projected loading.

Q. How does the Company determine the capacity of individual elements of the electric system?

A. The Company's design engineers determine the capacity of elements based on manufacturer or industry resource standards (i.e. IEEE). Multiple data sets and software programs are used to assist in determining capacity of each element.

Q. How are the Company's equipment ratings developed?

A. Equipment ratings — essentially the capability of a piece of equipment — are developed to ensure equipment is capable of handling peak hour loading over multiple hours, not just a

single peak hour. In other words, equipment ratings are based on an ability to handle load at a particularly sustained loading level for a period. The Company bases its equipment ratings on manufacturer or industry resource standards (i.e. IEEE).

Q. Can you provide an example of a Load Carrying Capabilities and Voltage Support Project?

A. Yes. A recent example is from the Midland area, where forecasted loading was projected to exceed the capacity of the 46 kV Coleman Lines and Warren 138/46 kV Substation for certain transmission system contingencies. Alternatives considered included a transmission level solution for the transmission company to construct a new 20+ mile long 138 kV line and several transmission substation upgrades versus a distribution level solution for the Company to rebuild 13.9 miles of the Coleman 46 kV line. Ultimately, the distribution project to rebuild the Coleman 46 kV line was selected as it most directly addressed the projected overloads and was the least cost alternative.

Q. What projects are funded through the New Interconnections investment category?

A. The New Interconnections category contains new interconnections to other utilities and generation facilities that must be completed as requested by the interconnecting party. Costs to interconnect other utilities and generation facilities to the Company's HVD system are reimbursed by the other utilities or generators being interconnected.

Q. Has the Company made any changes to the New Interconnections investment category? If so, please explain why these changes were completed.

A. Prior to 2024, the New Interconnections investment category also contained HVD interconnections to LVD substations. For example, a new 46 kV line might be needed to connect a new LVD substation to the existing HVD system. Starting in 2024, these HVD

facilities needed to connect an LVD substation to the HVD system are included with the LVD substation project in the applicable LVD substation sub-programs, which are discussed by Company witness Partlan. This change was made to better align the planning for scope, schedule, and budget for all portions of a project to the overall initiating need. In other words, if an LVD substation project is planned, then the full scope for that LVD substation project, including any needed HVD lines, will now all be contained within the LVD substation project itself.

Q. What projects are funded through the Improved Functionality investment category?

A. The Improved Functionality category contains projects that are completed to meet changes in standards and upgrades to protective schemes for Grid Operability/Reliability on a planned basis over a period. An example of this is the Company alleviating substation NESC working space issues systematically over a 10-year period. It is often coordinated with other major projects as they occur at the same location. Configuration changes to improve operability are made at the request of the Grid Management group or through coordination with other major projects as they occur at the same location. As discussed earlier in my direct testimony on the HVD Lines Reliability sub-program, the Improved Functionality investment category includes line sensors through the end of the 2024 calendar year, after which they were shifted to HVD Lines Reliability.

Q. What projects are funded through the Coordination with Transmission investment category?

A. The Coordination with Transmission projects, such as HVD relay upgrades associated with transmission upgrades, must be coordinated with those transmission upgrade projects that

require HVD upgrades to be completed as well. These are completed as needed over time in conjunction with the transmission owner.

Q. What projects are funded through the ROW Procurement investment category?

A. When existing easements are insufficient, ROW Procurement projects are necessary to procure land or land rights for HVD lines and substation sites across the HVD Capacity capital sub-program prior to construction and can require significant lead time. Through the process of monitoring and studying load profiles and planning for future infrastructure rebuilds or replacements, properties are sought and procured to build electric infrastructure at the right point in time needed to serve customers or meet infrastructure rebuild or replacement project timelines.

Q. Has the Company made changes to the ROW Procurement category within this sub-program for calendar year 2024 and beyond?

A. Prior to 2024, the ROW Procurement category within this sub-program contained ROW procurement for all HVD ROW needs, including ROW needed for projects in other sub-programs. For example, ROW needed for a new 46 kV line, to connect a new LVD Substation, or for an HVD line or substation rebuild would have been included in HVD Lines and Substations Capacity. Starting in 2024, these ROW acquisitions for projects in other sub-programs are included within those other respective sub-programs. This change was done to better align the planning for scope, schedule, and budget for all portions of a project to the overall initiating need.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery in the HVD Lines and Substations Capacity sub-program?

A. The Company is projecting in the bridge period HVD Lines and Substations Capacity capital expenditures of $40,913,000, and test year expenditures of $29,447,000, as shown in Exhibit A-116 (MPK-6), line 2. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 54 below.

FIGURE 54
HVD LINES AND SUBSTATIONS CAPACITY INVESTMENT CATEGORY EXPENDITURES AND PROJECTS

Investment Categories	Bridge Period Capital	# Units	Test Year Capital	# Units	Benefits*
Load carrying capabilities and voltage support	$16,494,000	4	$7,701,000	3	Avoid overload, mitigate inadequate clearance, offset transmission costs, 978,507 customer minutes
Improved functionality	$12,153,000	29	$7,441,000	12	Regulatory compliance, mitigate inadequate clearance, new standards, safety, grid operability/reliability, 17,650 customer minutes
Coordination with Transmission	$6,293,000	15	$9,226,000	9	Contractual requirement to coordinate with Transmission projects
ROW procurement	$5,972,000	8	$5,079,000	3	Needed to support ROW needs for many projects
Total	**$40,913,000**		**$29,447,000**		

*NOTE: All customer minutes are summarized by project in Exhibits A-109 (MLH-3) and A-110 (MLH-4).

Q. What is the basis for the requested spending level for the HVD Lines and Substations Capacity sub-program in this filing?

A. The requested spending levels for the bridge period and test year are based on the total of all costs in the Company's workplan. The cost projections in this sub-program were developed using derived costs, where available, that have been based on historical actuals experienced for similar projects. In many cases, the costs are also further refined with support from the Company's design and project management departments, taking into consideration the specifics of each project such as the location, expected site conditions, and up-to-date material and labor costs. The spending amounts for the bridge period and test year are determined by the combined costs of individual projects and will allow the Company to complete the projects listed, and deliver the benefits summarized above. The capital projects planned for the bridge period and the test year, as well as their investment categories, locations, and benefits to reliability are shown in Exhibits A-109 (MLH-3), page 9, and A-110 (MLH-4), page 9.

Q. Exhibit A-109 (MLH-3), page 9, line 23, indicates that the requested bridge period and test year spending amounts are higher than historical average. Are there projects in the bridge period and test year that are driving this increase?

A. Yes. The spending in both the bridge period and the test year is higher than the historical average due to the increased amount of work needed in the sub-program, with several large projects beyond typical historical levels. In the bridge period, one such project is the Coleman 46 kV 14-mile rebuild project. This project is needed due to a generator being connected to the transmission system in the area that would overload this line. Rebuilding the Coleman line is a more cost-effective alternative than further transmission system

upgrades to mitigate that same overload. This project is listed in Exhibit A-109 (MLH-3), page 9, line 30. The bridge period also includes a project to rebuild 3.1 miles of the Larkin 46 kV line to address inadequate clearance and capacity. This project is listed in Exhibit A-109 (MLH-3), page 9, line 31.

Other large projects needed in the test year are the Linden 46 kV line rebuild, needed to address a projected overload on this line (see Exhibit A-110 (MLH-4), page 9, line 14); and the Wealthy Street 138/46 kV Substation project needed to coordinate with a METC Transmission project (see Exhibit A-110 (MLH-4), page 9, line 25).

Q. What benefits will customers realize through the Company completing work in the HVD Lines and Substations Capacity sub-program?

A. Because the HVD system is the backbone infrastructure of the electric distribution network, projects in this sub-program must be completed on an as-needed basis to serve customers and maintain the safety and overall reliability of the grid. This sub-program ensures that the HVD system has the capacity to accommodate potential changes to the load profiles needed for new and changing technologies such as electrical vehicles and other potential electric growth in the future due to emerging technologies. Although this sub-program is not specifically designed to address system deterioration, investments in this sub-program improve system reliability and safety, and prevent future overloads, which can trigger dangerous wire downs and equipment failures due to exceedance of equipment interrupting capability.

Q. What has been the historical actual spending in the HVD Lines and Substations Capacity sub-program for the past five years?

A. The Company's historical actual spending in the HVD Lines and Substations Capacity sub-program for the past five years is shown in Figure 55 below.

FIGURE 55
HVD SYSTEM CAPACITY HISTORICAL SPENDING

2020	2021	2022	2023	2024	5-Year Average
$19,247,000	$17,365,000	$29,292,000,	$25,805,000	$27,163,000	$23,775,000

Q. Please explain year-over-year variation in spending in this program.

A. Projects in this sub-program have a variety of specific needs and in-service dates. Additionally, projects in this sub-program vary greatly depending on the required system upgrades, ranging from $10,000 or less for upgrading/replacing smaller equipment to several million dollars where an entire new substation or HVD line is needed, as can be seen in the project lists in Exhibits A-109 (MLH-3), page 9, and A-110 (MLH-4), page 9. Therefore, year-over-year variation in this program is driven by the timing needs of completing projects with such a great variance in scope and costs. Many of the projects are also driven either by a need to provide capacity before equipment overloads or by coordination with other parties, such as transmission owners, other utilities, and generation interconnections. Therefore, changes in load projections and changes in coordinating project schedules can drive variability in timing of spending. Combined with the very large costs of some projects, this can shift large amounts of spending from year to year.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No, the unit for this sub-program is projects, and the projects undertaken are specifically tailored and unique to only what must be performed, so the scope and cost of each project varies from project to project. There is a wide variance among work required ranging from approximately $10,000 or less for upgrading/replacing smaller equipment to as high as $10,000,000 or more where an entire new substation or HVD line is needed.

b) <u>LVD Substations Capacity</u>

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Substations Capacity sub-program.

A. The LVD Substations Capacity sub-program ensures the long-term safe and reliable operation of the Company's electric distribution LVD substations. The necessary capital expenditures include investments to install new substations or substation equipment, and to upgrade existing substations or substation equipment to ensure customer electric loads are served within the operating capacity of the installed substation equipment (i.e. transformers, fuses, reclosers, regulators, and switches). The LVD Substations Capacity investments are divided into two categories: new substations and existing substation capacity increases.

Q. What other work will be completed in the LVD Substation Capacity sub-program?

A. Starting in 2024, two work items were incorporated into the LVD Substation Capacity sub-program. HVD line work and ROW procurement associated with new and existing LVD Substation Capacity sub-program projects had been part of the HVD Lines and Substation Capacity sub-program investments. To improve investment categorization and project cost tracking, HVD line work and ROW procurement associated with LVD Substation Capacity projects are included in the LVD Substation Capacity sub-program.

Q. Did the Company consider any alternative approaches to project selection that could help achieve the Reliability Roadmap objectives?

A. Yes. Alternatives typically considered for each project include:

(i) transferring load to an adjacent and less loaded substation or line;

(ii) upgrading equipment or lines to provide the needed capacity;

(iii) building a new LVD substation to share the load capacity; and

(iv) connecting to a different HVD source.

Each project is selected based upon its effectiveness at solving the identified problem, the cost of the project, and the relative benefits.

Q. What benefits will customers realize through the Company completing work in the LVD Substations Capacity sub-program?

A. LVD Substations Capacity investments are necessary for the overall operation and reliability of the electric distribution system by preventing future overloads and addressing existing overloads, which would eventually result in equipment failure and customer outages, while ensuring the Company has adequate capacity on the distribution system to serve customer load. The number of customers benefitting from each project in this sub-program in the bridge period are identified in the Benefit Type and Benefit columns of Exhibit A-109 (MLH-3), page 10, and for the test year, listed in Exhibit A-110 (MLH-4), page 10.

Q. How does the Company identify LVD Substations Capacity projects?

A. LVD Substations Capacity planning projects are developed to respond to peak load conditions. Monitoring with DSCADA and analysis are done to identify situations where a component of the LVD substation has experienced an overload of its rated capacity. These

substation components are selected for a capacity upgrade project. If necessary, LVD substation capacity projects are prioritized to address the highest overloads in advance of lower overloads, with adjustments made for other factors such as historical reliability, customer mix, and safety impact. When assessing loads, the Company prudently considers actual and known new business load additions.

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Substations Capacity sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-109 (MLH-3), page 10, and for the test year, listed in Exhibit A-110 (MLH-4), page 10. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the location and benefits of the projects.

Q. Are NWS considered in the LVD Substations Capacity sub-program?

A. Yes. The Company has been exploring the potential for considering NWS as another alternative LVD substation capacity solution in recent years. Through recent pilots, the Company has refined its selection criteria for identifying potential LVD substations where NWS can be considered, with criteria including the peak load reduction needed, the timeframe of the projected need, customer mix, and other factors. The Company has already begun considering NWS, including solar and batteries, in some of its concept approvals for projects in this sub-program. However, as Company witness Kelly discusses in his direct testimony, the Company is also still early in the process of exploring how NWS can solve capacity and reliability issues on the system, and the Company is developing a new pilot in 2025 to better understand NWS applications.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Substations Capacity sub-program?

A. The Company is projecting LVD Substations Capacity capital expenditures of $29,656,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 24, column (k), and $22,251,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 24, column (l). The Company's historical actual spending in the LVD Substations Capacity sub-program, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 24.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The Company's projected spending for the LVD Substations Capacity sub-program is based on the Company's identified capacity needs and planned projects to mitigate planning criteria violations. The bridge period spending amount was determined based on the amount of investment needed to complete the projects identified.

Project costs were determined based on the specific work scope for each project and historical costs from similar projects. This level of work and the associated spending are adequate to meet the sub-program objective to serve customer electric loads within the operating capacity of the installed substation equipment, thereby ensuring the long-term and reliable operation of the electric distribution LVD substations.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the two investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 56.

FIGURE 56
LVD SUBSTATIONS CAPACITY INVESTMENT CATEGORY EXPENDITURES AND PROJECTS

Investment Categories	Bridge Period Capital	Bridge Period # of Projects	Test Year Capital	Test Year # of Projects
New substations	$5,136,000	4	$20,303,000	11
Existing substations projects	$24,520,000	19	$1,948,000	4
Total	**$29,656,000**	**23**	**$22,251,000**	**15**

Q. Please explain the year-over-year variation in spending in this sub-program.

A. The spending variation in the LVD Substations Capacity sub-program from 2020 to 2024 was based upon the types of projects that were required to address the capacity issues in those years.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Average unit cost is not a good measure of spending to predict the cost of an individual project for this sub-program due to the variation in specific work scopes needed for each project.

3. ELECTRIC OTHER PROGRAM

Q. What is included in the Electric Other Program?

A. Company witness Kelly introduces the Electric Other Program in his direct testimony. The Electric Other Program includes the following sub-programs in the test year:

- Computers and Equipment
- System Control Projects
- Grid Technologies

The Electric Other Program also includes the Tools sub-program, which is addressed by Company witness Partlan in her direct testimony.

a) Computers and Equipment

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the Computers and Equipment sub-program.

A. The Computers and Equipment sub-program consists of the capital costs to purchase and replenish computer equipment for electric distribution purposes.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Computers and Equipment sub-program?

A. The Company is projecting bridge period capital expenditures of $75,000 in this sub-program, as shown in Exhibit A-113 (MPK-3), line 42, column (k). This spending is primarily for new field devices. The Company is projecting test year capital expenditures in this sub-program of $75,000, as shown in Exhibit A-113 (MPK-3), line 42, column (l). As shown in Exhibit A-113 (MPK-3), line 42, column (m), this amount is lower than the five-year average spending for this sub-program.

Q. Why were spending levels in this sub-program significantly higher in 2022?

A. Higher spending levels in 2022 were related to a Scheduling Optimization project. The purpose of the Scheduling Optimization project is to better ensure the Company gets the right crew on site at the right time, so that field work can be completed right the first time and in a safe manner. In 2022, the Company developed and deployed a new digital tool called "iSchedule" as a part of this effort. This project was addressed in Case No. U-21389.

b) System Control Projects

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the System Control Projects sub-program.

A. The System Control Projects sub-program consists of projects to improve management of the distribution system, by improving operations of control centers, streamlining operations, and improving remote control capabilities to improve safety and reliability. This work includes operating technology enhancements and operations center modifications.

Q. What is included in operating technology enhancements?

A. Operating technology enhancements improve functionality and operations of the:

- System Control Center ("SCC") - Monitor and maintain the 46 kV and 138 kV HVD Systems;
- Distribution Control Center ("DCC") – Monitor and maintain LVD Substations and 3-phase backbone of the LVD system; and
- Work Management Centers ("WMC") - Monitor and maintain the LVD system and responsible for outage restoration by managing crews on the LVD system.

These three groups are responsible for monitoring the system and ensuring a reliable power supply for all customers. To manage a system of this size, these centers use technology specifically designed for real-time operations. Specific enhancements can vary from year to year.

Q. What is included in operations center modifications?

A. This consists of additional equipment and infrastructure to improve the Emergency Operations Center ("EOC"). These initiatives are typically identified during the after-action-reviews ("AAR") for each event. Examples of these kind of initiatives include small upgrades to office spaces to accommodate personnel and larger computer monitors to increase situational awareness.

Q. What benefits will customers realize through the Company completing work in the System Control Projects sub-program?

A. Improving monitoring and control capabilities on the distribution system helps streamline operations and reduce the impact of any single fault, reducing interruptions for customers. The technology enhancements and control room modifications will better enable employees to provide safe and reliable electricity.

Q. What is the basis for the Company's projected investment in System Control Projects in the instant case?

A. In Case No. U-21585, the Company projected test year investment of $279,000 for this sub-program, and this amount was approved by the Commission. In the instant case, the Company is maintaining projected investment levels at approximately the same amount, as shown in Exhibit A-113 (MPK-3), line 44.

Q. What has been the historical actual spending in the System Control Projects sub-program for the past five years?

A. The Company's historical actual spending is shown in Figure 57 below.

FIGURE 57
SYSTEM CONTROL PROJECTS HISTORIC EXPENDITURES

2020	2021	2022	2023	2024	5-Year Average
$975,812	$1,193,498	$2,179,436	$41,000	$896,000	$1,057,000

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Spending in this sub-program is inherently variable on a year-over-year basis primarily because this sub-program consists of discrete one-time projects that will not necessarily be repeated from year to year. Given technology programs may cost a relatively large amount

to purchase in one year, but then once purchased there is no additional spending for that technology in subsequent years. Test year spending in this sub-program is lower than the five-year historical average for two primary reasons. First, as the Company plans to transition to a Unified Control Center, less investment is needed in the existing facilities that will be replaced. Second, work that has historically been performed in the HVD Operations Projects investment category is being transitioned largely to the HVD Lines Reliability sub-program, reducing the total amount spent in System Control Projects.

B. Unplanned Spending Programs

1. HVD STRATEGIC CUSTOMERS NEW BUSINESS

Q. What is the purpose of the New Business Program?

A. The overall New Business Program includes the capital costs of connecting new commercial, industrial, and residential customers to the Company's distribution grid, as discussed by Company witness Kelly in his direct testimony. Because of the Company's obligation to serve customers in its service territory, the Company generally is required to provide the requested interconnections.

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the HVD Strategic Customers New Business sub-program.

A. The HVD Strategic Customers New Business sub-program consists of the capital costs to meet the new business needs of large C&I customers that are too energy intensive to be served by the area LVD system, addressing both existing customers and potential new customers to locate a new facility in Michigan. Typical investments for this program include dedicated substations and interconnections of dedicated substations to the HVD system with poles, conductors, and metering to connect new C&I customers.

Q. How does the Company plan projects and develop investment projections in this sub-program?

A. Projected test year spending amounts are based on planned projects to meet customer commitments, plus projects with a high probability of moving forward in the near future, such that bridge or test year spending amounts would be needed, as discussed in more detail below. These costs are net of any expected contributions made to the Company by customers in support of their project. Customer service inquiries in this sub-program are continuous and are driven by customer business needs. Unlike many of the Company's other capital programs, this sub-program and its timing of projects and investments are driven to meet the needs and expectations of specific customers. The timeline from a completed customer agreement to a final connection can vary from six months to two or more years. While some projects are known well enough in advance to be captured in a rate case filing, in other cases they are not.

Q. Please explain how the Company identifies projects to account for spending in this sub-program.

A. The Company identifies projects as they are requested by customers. Customers typically contact the Company's Business Customer Care team, who refers the customer to the HVD planning engineer for the corresponding geographic location. The customer will identify their location, proposed new maximum electrical demand, a proposed schedule for the new electric load to come online, as well as other information. The HVD planning engineer performs studies and develops conceptual cost estimates for any required new or upgraded Company facilities to serve the new load, including any Contribution in Aid of Construction ("CIAC") costs applicable to the customer. The conceptual cost estimates are developed by

the Company's project management team using derived costs, where available, based on historical actual costs for similar projects. The costs are also further refined with support from the Company's design and project management departments prior to customer agreements being executed, taking into consideration the specifics of each project such as the location, expected site conditions, and up-to-date material and labor costs. If costs are agreed to by the customer, a schedule for the work is developed.

Q. What are the Company's projected bridge year and test year spending levels, for which it is requesting cost recovery, in the HVD Strategic Customers New Business sub-program?

A. The Company is projecting HVD Strategic Customers New Business capital expenditures of $90,045,000 in the bridge period, and $43,860,000 in the test year, as shown in Figure 58 below.

FIGURE 58
HVD STRATEGIC CUSTOMERS NEW BUSINESS INVESTMENT CATEGORY
PROJECTED EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units	Benefits
Projects	$90,045,000	6	$43,860,000	4	Obligation to Serve, Economic/Community Impact (see Figure 43)
Total	**$90,045,000**	**6**	**$43,860,000**	**4**	

Q. What is the basis for the Company's requested spending level for the HVD Strategic Customers New Business sub-program in this filing?

A. The projected spending for the bridge period and the test year is primarily based on projects to which customers have committed to moving forward. These projects are listed in Exhibit A-109 (MLH-3), page 11, and Exhibit A-110 (MLH-4), page 11.

Q. Have customers committed to moving forward with all of the listed projects?

A. Yes, with one exception. Exhibit A-109 (MLH-3), page 11, line 2, refers to a new 138 kV dedicated customer's substation in northwest Michigan. This project was associated with a customer that did have a fully committed contract with the Company, and the Commission approved spending on this project in Case No. U-21585. However, in April 2025 this contract was terminated after the customer's postponement of construction continued for more than 12 months. Because a contract existed and because expenditures had been approved by the Commission, the Company has already made some expenditures in the bridge period, and the Company is seeking recovery of these expenditures that were made in good faith. Pursuant to that termination and language in the customer's contract with the Company, the customer is required to reimburse the Company for costs incurred for the project. Specifically, the customer is required to pay the Company the entire cost for work performed, materials not salvaged, and all reasonable cancellation expenses incurred to provide service, without interest, less payment made by the customer. If and when the Company recovers these costs from the customer, that money will be credited to this sub-program and netted back out of rate base.

Q. Is there any other spending in Exhibit A-109 (MLH-3), page 11, or Exhibit A-110 (MLH-4), page 11, that is not tied to projects to which customers have fully committed?

A. The Company also has some spending included for certain high probability projects that are in active contract negotiation that are very likely to move forward in the near future, such that the Company must invest in the bridge period and test year in order to ensure that customer needs can be met.

Q. Please further discuss this "high probability projects" item that is listed in Exhibit A-109 (MLH-3), page 11, line 7, and Exhibit A-110 (MLH-4), page 11, line 7.

A. The Company is engaged in multiple inquiries, working in conjunction with the Michigan Economic Development Corporation ("MEDC") and other local economic development groups, to accommodate prospective new large industrial customers considering siting in Michigan. The high probability projects item represents the C&I developments that the Company is in active contract negotiations on, and which have a high probability of moving forward in the near future, requiring spending in both the bridge period and/or the test year. For these high probability projects, the customer either has accepted a commitment offer letter from the MEDC and/or has identified a specific site in the Company's service territory for location. These projects have long lead times in terms of ordering materials and other logistical considerations, and prospective large customers need the certainty that they will be able to connect to the Company's system on their schedule. Consequently, for these high probability projects the Company often must begin purchasing materials and doing other work in advance.

Q. Can you provide any relevant benchmarking or industry references outside of the Company's specific experience that supports the need to procure long lead material and do other advance work to accommodate new and expanding customers?

A. Yes. The Site Selectors Guild, an association of global professional site selection consultants, partnered with Development Counsellors International to complete *The State of Site Selection 2024* report[1], a primary research study that identifies the top trends impacting the facility location decision-making process in the United States and globally.

[1] Available at https://siteselectorsguild.com/research/the-state-of-site-selection-2024/.

It provides a thorough review of the background and collective industry knowledge that has historically influenced site selection decisions. It also provides a sound basis for the Company's approach to responding to new business requests. The study found that 87% of Guild members strongly agree that resource shortages (including with utilities) have challenged or compromised project timelines (page 10). "Utilities/Infrastructure" continues to be identified as a top factor impacting the site selection industry in 2024 (page 11). Furthermore, 79% of Guild members identified "Utilities/Infrastructure" as *the* top factor impacting site selection in 2024 for Industrial customers, and 64% identified the availability of development-ready sites as the third most critical factor to industrial customers (page 12). Almost all Guild members that participated (96%) agreed that access to development-ready sites will significantly impact the future of industrial projects (page 18). The report recognizes that there is a scarcity of industrial sites with 82% of Guild members strongly agreeing that for industrial projects, the availability of development-ready sites with sufficient infrastructure capacity is the top location driver in 2024 (page 20). Directly related to the state of utilities and infrastructure, 98% of Guild members believe access to sufficient electric capacity will significantly impact the future of industrial projects (page 35). Guild members also agree that the most significant impacting factors to industrial projects are electric power capacity, with a 4.7 significance rating (out of a 5-point scale of significance) and access to development-ready sites at 4.6 significance rating (page 37). 98% of Guild members that participated in this study are in agreement that electric power capacity will significantly impact the future of industrial projects (page 38).

The quotes below from the study are consistent with the Company's experience:

> In the U.S., the supply of industrial sites with adequate labor, utilities and access has been significantly reduced due to

> economic growth in the industrial sector over the last 10 to 15 years. In terms of the site selection process, intensified screening of sites at early stages of projects is critically important to verify fatal flaws. [Mark Williams, Strategic Development Group Inc. (page 17 of the report)]
>
> The biggest challenge facing the industrial market is the lack of development-ready sites with desired available utility capacity. When utilities require upgrades to meet capacity needs, you are looking at a 24- to 36-month timeline for that to occur, which rarely meets a company's plant startup timeline these days. Everything is moving at a faster pace, so if you are a community that truly wants to attract new jobs and investment to your community, you must get your sites and infrastructure prepared ahead of these search inquiries. There is just no way around it. [Michelle Comerford, Biggens Lacy Shapiro & Company (page 23 of the report)]
>
> High energy demands with many of the EV/clean fuel/semiconductor projects, along with the transition away from carbon-based generation, are causing a significant stress on the grid causing delays in project timelines. [John Longshore, Newmark (page 36 of the report)]
>
> So many projects have required massive amounts of electric power and often other utilities, which has strained capacity in nearly all locations that are typically attractive to manufacturers…..Lengthy waits to get transformers – sometimes quoted at 36 months now – quickly eliminates otherwise top locations. Smaller to midsized projects, which could become the norm again after this big push on electric vehicles, semiconductors and solar production abates, are a bit less impacted and have more choices, but the capacity constraints will start affect their choices and certainly their costs. [Phil Schneider, Schneider Strategy Consulting LLC (page 41)]

Q. What has been the historical actual spending in the HVD Strategic Customers New Business sub-program for the past five years?

A. The Company's historical actual spending in this sub-program for the past five calendar years is shown in Figure 59 below.

FIGURE 59
HVD STRATEGIC CUSTOMERS NEW BUSINESS HISTORIC EXPENDITURES ($000)

2020	2021	2022	2023	2024	5-Year Average
$4,038	$20,268	$4,280	$11,071	$57,836	$19,499

Q. Why does historical spending in this sub-program show significant year-to-year variation?

A. Spending in this sub-program can be inherently variable from year to year because the projects and investments undertaken are relatively few and are specifically tailored to the needs of the customers requesting the work. This was particularly illustrated in 2021 and 2024, when the Company worked on a couple of large customer projects in this sub-program that accounted for the higher costs in those years. The amount of anticipated load and redundancy requirements determines the required number and size of large substation transformers, which is typically a large driver of costs in this sub-program. For example, one of the large projects that occurred in 2024 was for a new 138-kV four-transformer dedicated customer substation with four 75 MVA transformers, with project spending of approximately $18 million in 2024, and expected total project spending of $45.6 million over three years. Conversely, a project in 2020 for a new single-transformer dedicated customer substation with a 30 MVA transformer had a total project cost of about $3.5 million. There can also be some projects that are relatively minor upgrades required to serve smaller customers that cost less than $100,000. The work completed in this sub-program is performed to provide new or upgraded facilities required to serve new or existing customers.

Q. Why is the requested spending level for the bridge period and the test year greater than the historical spending in this sub-program?

A. As stated above, spending in this sub-program is based on unique customer requests and projects that are tailored to the needs of the customer requesting work. Similar to 2021 and 2024, but on an even larger scale, the bridge period and the test year contain several large projects that are needed to serve several very large customers. These include a new larger-than-typical 138 kV dedicated customer substation needing two 75 MVA transformers to serve a large customer in southern Michigan; a new larger-than-typical 138 kV dedicated customer substation needing four 75 MVA transformers to serve a large customer in east Michigan; a new larger-than-typical customer requiring two 138 kV dedicated customer substations needing two 75 MVA transformers and three 150 MVA transformers to serve a large customer in west Michigan; a new larger-than-typical 138 kV dedicated customer substation needing two 150 MVA transformers in southeast Michigan; and a new 46 kV customer substation to serve a customer in west Michigan. These span both the bridge period and the test year with larger than historical spending required to complete these projects. The projected spending amounts for these projects are shown in Exhibit A-109 (MLH-3), page 11, and Exhibit A-110 (MLH-4), page 11.

Q. What benefits do customers receive through the Company completing work in the HVD Strategic Customers New Business sub-program?

A. The investments in this sub-program are necessary for C&I customers to expand their facilities, allowing those customers to further develop their businesses. This also benefits the broader economy of the state of Michigan. Increased large new customer connection and load additions provide the benefits of job development, and other state and local revenue

streams associated with business expansion. Figure 60 below illustrates examples of the benefits and impacts of two committed projects in progress (included in the bridge period and test year) and the associated community impact.

FIGURE 60
HVD STRATEGIC CUSTOMERS NEW BUSINESS RECENT PROJECT IMPACTS

Project Name	Community Impact
New 138 kV dedicated customer Substation in southern Michigan	The customer is constructing a new electric vehicle battery manufacturing facility. The project has the potential to result in the creation of up to 1,700 new jobs and a capital investment of up to $2.6 billion. Up to $29.7 billion in new personal income could be generated over 20 years by the direct, indirect, and induced jobs that this opportunity will create.
New 138 kV dedicated customer Substation in east Michigan	The customer announced and will be constructing a new manufacturing facility. The project has the potential to result in the creation of up to 1,100 new jobs paying an average wage of over $28/hour and over $900 million in private investment. The project is expected to spur spin-off investments and redevelopment, as well as $5.6 billion in new personal income over the next 20 years.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. The historical unit costs for this sub-program reflect projects that vary significantly in size and scale. Each project in this sub-program is specifically designed to meet the needs of the individual C&I customer who requests the project.

2. METRO NEW BUSINESS

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the Metro New Business sub-program.

A. The Metro New Business sub-program responds to electrical energy needs of new construction and existing metered locations served by the Company's Metro underground territories. The Company typically needs to extend both the underground civil infrastructure, such as ductwork, and the electrical system to accommodate new business requests.

Q. How does the Company generally handle new business requests on the Metro system?

A. Metro New Business customers are connected to the system at no cost, in accordance with rate administration and billing rules in the Company's MPSC-approved tariffs, specifically Section C6.2 Underground Policy, Part F. These customers commonly fall into two categories: (i) *primary service*, typically large commercial, government, and healthcare facilities; and (ii) *secondary servic*e, typically commercial retail use, mixed use, or residential buildings in accordance with the Company's MPSC-approved tariffs, specifically C1.6 General Provisions of Service and C4.3 Application of Residential Usage and Non-Residential Usage.

Q. What benefits will customers realize through the Company completing work in the Metro New Business sub-program?

A. Metro New Business projects primarily benefit the customers being connected. Service connections vary by electrical demand. Primary services are typically provided in a loop feed, primary selective, or split bus design that provides reliable service. Secondary services are radial in nature and sized to the service meter and customer electrical panel size to allow for future electric growth without subsequent upgrades. Economic growth in the six metro

downtowns depend on the ability of new residential and commercial customers to access utilities, including electricity.

As with other work in the New Business Program, all customers ultimately benefit from the load growth driven by new customers, as system-wide fixed costs are spread across a broader base. The projected spending level will allow the Company to provide a new service installation to every customer who requests it.

Q. How does the Company identify Metro New Business projects?

A. The Company identifies projects as they are requested by customers, as is common throughout the New Business Program. The Company has identified projects needed to fulfill customer requests for the bridge period, which are listed in Exhibit A-109 (MLH-3), page 12. The Company has also identified projects, for the test year, which are listed in Exhibit A-110 (MLH-4), page 12. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects.

Additionally, the Company is aware of several prospective projects that could progress and require additional investment in the test year. The Company is holding ongoing discussions with these customers, including:

- Continuation of construction of a 380,000 square-foot event center and arena in Kalamazoo;
- Continuation of construction of the 10 acre, 12,000 seat Acrisure Amphitheater in Grand Rapids;
- Re-development of existing vacant buildings to mixed-use in Jackson;
- Numerous new mixed-use high-rise type buildings in Grand Rapids;
- A 200-unit apartment complex in Flint; and
- The new zoned planned unit development in Saginaw for the Saginaw Medical Diamond medical offices and mixed-use buildings.

Q. Are there projects that are not currently known, but that could be reprioritized to take place during the test year, if circumstances change?

A. While Metro New Business projects can be identified in advance on some occasions, project timelines can be fluid because customers' own development timelines often change in response to various factors. The projects listed in the exhibits are those that the Company expects to perform in the bridge period and test year. However, it is possible that one or more customers could request a project for 2026 or later, and then subsequently request the Company perform the work sooner if the customer has a change in timeline.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Metro New Business sub-program?

A. The Company is projecting Metro New Business capital expenditures of $6,453,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 4, column (k), and $7,917,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 4, column (l). The Company's historical actual spending in the Metro New Business sub-program, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 4.

Q. How does the Company develop its projected expenditures in this sub-program?

A. In some cases, customers contact the Company in advance, allowing for Metro New Business project costs to be determined and planned for in longer-range spending forecasts. However, even with advance notice, customers' respective developments may take years to come to fruition, as customers seek funding and address other issues relative to economic development in urban core areas. Therefore, even advance notice Metro New Business projects may not be completed on the originally proposed timeline. In other cases, customers contact the Company later in their development process, with desired service

within that same year, meaning those Metro New Business project costs cannot be accounted for in longer-term forecasting. Therefore, the Company also uses analysis of historical spending levels to forecast the level of investment needed in this sub-program. The Company's projected bridge period and test year spending level in Metro New Business is in line with recent experience. There have been many inquiries, in addition to the identified projects, supporting that the projected Metro New Business expenditures for the test year will be higher than the past three years.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. The Company's recent investment in Metro New Business was at its highest in 2024, as there was significant economic development and urban renewal, with corresponding construction work, in several of the downtown areas served by the Company's Metro systems. For example, in Grand Rapids the amphitheater civil project required an investment of approximately $3,450,000 and the first phase of civil work for the Kalamazoo Event Center required an investment of approximately $4,830,000. These higher than historical costs were mainly driven by expansion of the Metro system to serve these new business loads. The Metro New Business expenditures in 2022 were lower than the prior five years due to project developer delays related to post-pandemic supply chain and inflationary pressures, and lack of construction labor resources. Investment in 2023 was lower than average as well due to project developer delays due to inflationary pressures and lack of construction labor resources.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Average unit cost is not a good measure to project the cost of a project in this sub-program. Metro projects have a wide variance in size, scope, and work required, ranging from $100,000 to as high as $5,000,000 per project.

3. HVD LINES AND SUBSTATIONS DEMAND FAILURES

Q. What is the purpose of the Demand Failures Program?

A. The overall purpose of the Demand Failures Program is to address issues related to customer interruptions and failures of equipment on the distribution system, as discussed by Company witness Kelly in his direct testimony. When the Company replaces failed equipment, the associated capital expenditures are part of the Demand Failures Program. The work in the Demand Failures Program is emergent; it is planned, prioritized, and completed as issues arise, with specific projects not planned far in advance. The HVD Lines and Substations Demand Failures sub-program specifically addresses failures on HVD lines and substations.

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the HVD Lines and Substations Demand Failures program.

A. The HVD Lines and Substations Demand Failures sub-program supports the capital replacement of failed 46 kV and 138 kV lines and substation equipment to restore customer service and maintain reliability. This sub-program replaces assets that have failed in the field, including HVD substation equipment, HVD poles and switches, and HVD cross-arms and insulators. The HVD Lines and Substations Demand Failures sub-program consists of the following investment categories addressing actual failures:

- Pole replacements

- Pole top assembly replacements
- Switch (including MOABS replacements)
- Miscellaneous other replacements
- HVD substation failure projects

The first four cited investment categories support projects on HVD lines.

Q. What types of investments are included in the HVD substation failure investment category?

A. The HVD substation failure investment category supports the replacement of equipment and infrastructure that has failed within an HVD substation and includes (but is not limited to) power transformers, circuit breakers, circuit switchers, capacitors, switches, bushings, station batteries/chargers, regulators, voltage transformers, and facilities (such as fences, gates, and driveways).

Q. What benefits will customers realize through the Company completing work, in the HVD Lines and Substations Demand Failures sub-program?

A. This sub-program is essential for the restoration of service to customers for the Company to meet its obligation to serve. As mentioned above, this sub-program is also utilized to address failed assets as they are identified prior to those failures causing an interruption to customers. The projected bridge and test year amounts provide for the level of investment necessary in HVD Lines and Substations Demand Failures needed to support capital repair or replacement of projected failed HVD equipment to address interruptions and meet the Company's obligation to serve customers.

In the majority of HVD Lines failures, customers are interrupted, and the Company must restore those customers as quickly and safely as possible. In 2024, there were 46 HVD

Line failures with an average of 2,750 customers interrupted per event, not including MED outages. For those situations where an HVD line failure occurs and customers are not interrupted, such failures put the system into a non-standard configuration, reducing system resiliency, that would likely result in a much larger outage if a second failure occurs. For HVD substations, outages to customers due to individual equipment failures are much rarer due to redundancies in the substations but they can be of significant size when they do occur. A 2024 failure of an oil circuit breaker at Verona substation near Battle Creek resulted in extended outages for 5,000 customers for more than 14 hours. Even more critical was the loss of system resiliency and redundance that prevented quick isolation of more than an additional 8,700 customers who were then without power for more than 22 hours. When an individual piece of equipment in a substation fails, the Company still needs to address that failure, even if no customers are interrupted, in order to maintain levels of redundancy.

Q. How does the Company identify and prioritize HVD Lines and Substations Demand Failures sub-program projects?

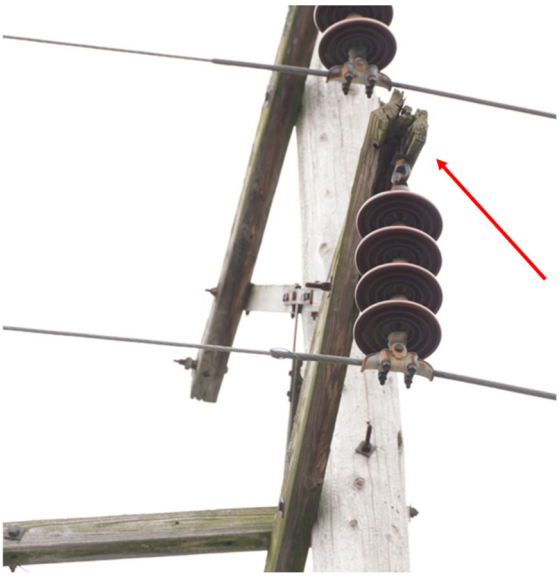
A. For HVD Lines, the Company determines work needs based on real-time HVD line component failures or very short-term imminent failures. The Company immediately responds to component failures resulting in customer outages identified from calls from customers, third parties, or by alarms from the SCADA system. Once notified, system operators and/or crews are quickly dispatched to locate the electric fault and restore power to customers. Data from digital relays and line sensors can often be used to pinpoint the location of the fault allowing crews to find the location faster.

Component failures that do not cause a line to trip, but decrease the integrity of the line, are addressed within weeks or months once discovered. These anomalies are identified

through routine annual helicopter patrols, biannual ground patrols, or through calls from customers, employees, or third parties. Examples include floating phases (when a phase wire becomes unsecured from an insulator), broken insulators, broken crossarms, broken poles, or broken static wires. Figure 61 below provides two examples of Priority 1 anomalies identified during helicopter inspections.

FIGURE 61

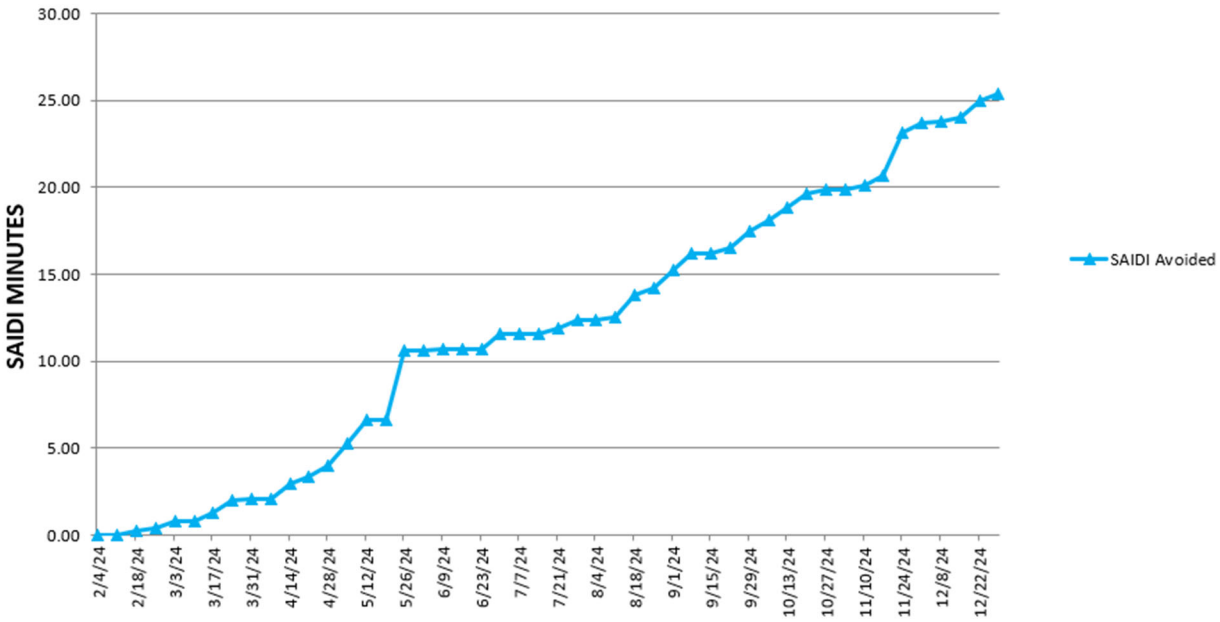




In 2024, the identification and correction of Priority 1 and 2 anomalies like the ones shown above, before those anomalies resulted in customer outages, avoided an estimated

25.3 SAIDI minutes. Figure 62 below shows the timeline in which failures are identified and corrected. The failures are assigned a projected SAIDI minute benefit that is realized after the correction has been made.

FIGURE 62
SAIDI avoided through correction of defects



For HVD Substations, the Company acts based on real-time failures, anomalies, and issues discovered through an annual inspection process. If an HVD substation equipment anomaly is causing an outage to customers or if its potential failure poses an immediate and intolerable electric system operating condition, it will be addressed immediately. If the equipment anomaly is not currently causing a customer outage, it will be addressed at a future point in time through the HVD Lines and Substation Rehabilitation sub-program or alternatively through the Reliability Program. Some projects, such as HVD transformer replacements with longer lead times, may be delayed if other replacements are identified that have a higher risk of failure or have failed in service.

Q. Why is the Company requesting approval for these expenditures in this proceeding?

A. Failure to repair faults that result in customer outages in a timely manner inhibits the Company's obligation to serve. Failure to address failed equipment that does not result in customer outages increases the risk of customer outages in the future if not addressed in a timely manner. The spending in this sub-program maintains customer reliability or in the event of a fault, restores customers quickly and safely.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the HVD Lines and Substations Demand Failures sub-program?

A. For the bridge period, the Company is projecting HVD Lines and Substations Demand Failures capital expenditures of $8,296,000, as shown in Exhibit A-113 (MPK-3), line 33, column (k). For the test year, the Company is projecting HVD Lines and Substations Demand Failures capital expenditures of $10,000,000, as shown in Exhibit A-113 (MPK-3), line 33, column (l). The bridge period and test year spending by investment category is broken down in Figure 63 below. Individual HVD substation failure projects can range widely in scope and cost, from small transformer replacements costing $12,000 up to large transformer replacements costing $2,000,000. This variation makes it impractical to project a unit total. Projected spending on HVD substation failure projects is based on historical actual spending without respect to units.

FIGURE 63
HVD LINES AND SUBSTATION DEMAND FAILURES INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Pole replacements	$2,387,470	80	$2,877,857	97
Pole top assembly replacements	$984,608	113	$1,186,846	137
Switch replacements	$735,631	6	$886,730	7
Miscellaneous/other replacements	$312,262	18	$376,400	22
HVD substation failure projects	$3,876,030	n/a	$4,672,167	n/a
Total	**$8,296,000**		**$10,000,000**	

Q. How did the Company develop its projected expenditures in this sub-program?

A. The spending forecast is based on the historical five-year average for this sub-program. Investment for this sub-program has increased in the last three years compared to the previous two years. In 2022, a failed cap switcher at the Litchfield substation cost $600,000; and the beginning of a failed transformer replacement project at the Halsey substation cost $1.2 million. Both of these contributed to higher spending. In 2023, the transformer replacement at the Halsey substation was completed, totaling an additional $700,000; and major transformer replacements at the Wackerly substation for $1.4 million and the Beaver Creek substation for $2.3 million accounted for the increased spending in this investment category. In 2024, a failed circuit breaker at Verona substation and resulting damage to adjacent equipment increased spending in this category by $1 million.

Q. What has been the historical actual spending in the HVD Lines and Substations Demand Failures sub-program for the past five years?

A. The Company's historical actual spending in the HVD Lines and Substations Demand Failures sub-program for the past five calendar years is shown below in Figure 64.

FIGURE 64
HVD LINES AND SUBSTATIONS DEMAND FAILURES HISTORIC EXPENDITURES ($000)

2020	2021	2022	2023	2024	5-Year Average
$6,782	$6,050	$10,015	$13,524	$11,705	$9,615

Q. What are the historical unit costs for each of the HVD Lines and Substations Demand Failures investment categories?

A. Historical unit costs for each lines-related investment category are identified in Figure 65 below.

FIGURE 65
HVD LINES AND SUBSTATIONS DEMAND FAILURES HISTORIC EXPENDITURES

Investment Categories	2020	2021	2022	2023	2024
Pole replacements	$29,200 /project	$18,800 /project	$33,100 /project	$30,465 /project	$45,714 /project
Pole top assembly replacements	$18,200/ project	$8,300/ project	$10,302/ project	$10,052/p roject	$9,707/ project
Switch replacements	$99,500 /project	$132,600 /project	$143,000 /project	$114,875 /project	$169,950 /project
Miscellaneous other replacements	$11,500 /project	$37,300 /project	$4,750 /project	$3,187 /project	$11,931 /project

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. Yes, with the exception of the miscellaneous other replacements investment category. Since the miscellaneous/other replacements investment category encompasses a wide variety of projects, the unit costs in that category show wide variation. It is possible to see variation in other investment categories, as accessibility and specific equipment factors can create increases in individual project costs.

4. LVD SUBSTATIONS DEMAND FAILIURES

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Substations Demand Failures sub-program.

A. The LVD Substations Demand Failures sub-program supports capital repair or replacement of failed LVD substation equipment to restore customer service and maintain reliability of electrical service. Work in the LVD Substations Demand Failures sub-program is planned and executed when an event has occurred. LVD Substations Demand Failures projects are divided into four investment categories:

(i) regulators;

(ii) reclosers;

(iii) transformers; and

(iv) other equipment.

Q. What has been the average failure population of the three main LVD substation components in the past five years?

A. Based on the five-year average from 2020 through 2024, the Company has experienced approximately four LVD substation transformer failures (approximately 0.38% of population); 43 recloser failures (approximately 0.84% of population); and 64 regulator failures (approximately 1.25% of population) per year. These historical failure rates are used to project investment needs going forward in this sub-program.

Q. What benefits will customers realize through the Company completing work in the LVD Substations Demand Failures sub-program?

A. The projected test year amount provides for the level of investment necessary in LVD Substations Demand Failures to support capital repair or replacement of failed LVD substation equipment to address interruptions, maintain service quality, and meet the

Company's obligation to serve customers. Absent investment in this category, customers would remain without electric service or experience unacceptable service quality when substation equipment fails. For example, if a substation transformer serving 5,000 customers failed, electric service to those customers would not return until the substation transformer was replaced or a mobile substation was temporarily installed. If a substation regulator serving 1,000 customers failed and was not replaced, those customers could eventually experience electrical equipment damage or electrical equipment may not function properly due to inadequate service voltage.

Q. Why is the Company requesting approval of these expenditures in this proceeding?

A. The work in this sub-program is essential to restoring interrupted electrical service to customers or to restore the safe and reliable operation of the substation.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Substations Demand Failures sub-program?

A. For the bridge period, the Company is projecting LVD Substations Demand Failures capital expenditures of $11,923,000, as shown in Exhibit A-113 (MPK-3), line 34, column (k). For the test year, the Company is projecting LVD Substations Demand Failures capital expenditures of $8,961,000, as shown in Exhibit A-113 (MPK-3), line 34, column (l). The Company's historical actual spending in the LVD Substations Demand Failures sub-program, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 34.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The Company's requested spending levels for the bridge period and test year are based on projected failure rates, which are in turn based on historical failure rates as defined above. The projected bridge period and test year capital expenditures were determined by evaluation of the 2020 through 2024 actual spend and based on projected future costs.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the four investment categories.

A. The Company is projecting unit and capital expenditures in the bridge and test years for each investment category as identified in Figure 66, based on the Company's average failure rates over the historical period of 2020 through 2024.

FIGURE 66
LVD SUBSTATIONS DEMAND FAILURES INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units
Regulators	$5,280,000	80	$3,960,000	60
Reclosers	$1,200,000	48	$900,000	36
Transformers	$3,380,000	4	$3,380,000	4
Other Equipment	$2,063,000	41	$721,000	14
Total	**$11,923,000**	**173**	**$8,961,000**	**114**

Q. Please explain the year-over-year variation in spending in this sub-program.

A. In 2021, the Company replaced two transformers that failed in 2020 but were replaced in 2021. Baum Street and Dewey Substations both have two transformers, so when one of the transformers failed at each substation in 2020, electric service was restored by temporarily transferring the impacted customers to the other transformer until the failed transformer replacement projects were completed in 2021. In 2023, six emergent projects contributed

to the majority of spending within the Other Equipment Replacements investment category. All six projects required mobile substations and three of those projects required substation structure modifications resulting in a higher project cost. In 2024, the Company replaced 30 more regulators than were originally forecasted, replaced 14 more reclosers than were originally forecasted, and 12 emergent projects contributed to the majority of spending within the Other Equipment Replacements investment category. The 12 emergent projects consisted of various equipment failures such as transformer bushings, transformer cooling fans, substation switches, and lightning arresters.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. Unit costs are generally a reasonable reflection of the expected project spending for the regulator, recloser, and transformer investment categories. Unit cost is not a good measure to project spend for the Other Equipment investment category due to varying work scopes that are generally required for each project.

5. METRO DEMAND FAILURES

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the Metro Demand Failures sub-program.

A. The Metro Demand Failures sub-program involves the replacement of failed cables, transformers, and civil infrastructure within the Company's Metro systems. Metro Demand Failures costs are highly dependent on the type of asset that fails. Civil assets such as manholes, vaults, and duct banks are highly labor intensive with correspondingly high restoration costs. Electrical asset failures are variable, as spare components (i.e. transformers and switches) are kept in local storerooms and can be replaced immediately. Primary cables are kept in storerooms and may be immediately replaced or replaced at a

later date given its loop or primary selective design. Secondary and service cables are designed in a radial nature, so secondary and service failures are immediately replaced to restore service.

The Company projects its needed investment level in this sub-program based on historical averages and trends. In this filing, spending in Metro Demand Failures is divided into three investment categories:

(i) Cable Failure and Replacement;

(ii) Transformer Failure and Replacement; and

(iii) Civil Infrastructure Failure and Replacement.

Q. Why does the Company perform replacement of electrical assets in this sub-program?

A. Electrical assets in Metro vaults may fail due to age, deterioration, standing water, and runoff contaminants (e.g. salt). The most common electrical assets that fail are Metro transformers, primary cable, and secondary cable. If a primary cable fails, the Company identifies potential switching schemes to immediately restore service to customers. After the fault is isolated and customers are restored, there are times when the Metro system is no longer in a loop or primary selective configuration (i.e. it no longer has feeds from multiple directions) and must be repaired. A design will be created for permanent repairs. By leaving this faulted section isolated for a long period of time, there would no longer be a way to restore service to customers from that direction. If a transformer fails, it is replaced with a spare unit. If a secondary cable fails, a new cable is pulled in a spare conduit adjacent to the failed cable. The failed cable is cut at both ends and removed, creating another spare conduit.

Q. What are the general factors that contribute to the need for investment in the Metro Demand Failures sub-program?

A. Many factors contribute to deterioration of the cabling, equipment, and civil infrastructure in the Metro systems, including age of the system and public damage. The Company commonly sees several specific problems caused by deteriorating electrical equipment including:

- primary cable failures;
- transformer and other electrical equipment failures; and
- secondary and services failures.

The Company commonly experiences public damage related failures resulting from:

- Work performed in the ROW without notification to the MISS DIG system;
- Improper directional boring techniques used by contractors performing work for other utilities in the ROW; and
- New business and redevelopment engineered plans, including parts of the ROW, with poor surveying and notification to the Company.

Q. What benefits will customers realize through the Company completing work in the Metro Demand Failures sub-program?

A. Absent investment in this category, customers would remain without electric service or the redundant portion of the metro system would remain out of service indefinitely. Leaving the redundant portion of the system out of service would eliminate the availability to complete restoration of other unplanned events. The projected bridge period and test year amounts provide for the level of investment in Metro Demand Failures needed to support capital repair or replacement of failed metro equipment to address interruptions, and to meet the Company's obligation to serve customers.

Q. Why is the Company requesting approval of these expenditures in this proceeding?

A. The work in this sub-program is essential to restore interrupted electrical service to customers served by the metro underground system or to make immediate repairs to the civil infrastructure to protect the public.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery in the Metro Demand Failures sub-program?

A. The Company is projecting capital expenditures of $664,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 36, column (k), and $350,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 36, column (l). The Company's historical actual spending in the Metro Demand Failures sub-program, along with the bridge period and test year forecasts, are shown in Exhibit A-113 (MPK-3), line 36.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The Company's projected bridge period and test year spending are based on a continuation of recent spending levels since 2021, after the re-categorization of imminent failure work to the Metro Rehabilitation sub-program.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Before 2020, the Company invested more than average in this sub-program to address imminent failure issues with civil and electrical infrastructure in the Flint and Jackson Metro systems. Today, that work would be addressed in the Metro Rehabilitation sub-program. This rehabilitation work has reduced the cost of failures in the Metro system. Beginning in 2021, the Company experienced fewer actual failures requiring equipment replacement, resulting in lower than average spending due to rehabilitation and reliability investments.

Q. Does an average unit cost accurately reflect the expected spending per project for this sub-program?

A. No. Average unit cost is not a good measure of spending to predict the cost of an individual project in this sub-program because of the variance in work required to address failures, which range from $4,500 to $60,000 per project. Additionally, the number of units completed each year is small, which inhibits reliable unit cost metrics.

6. HVD ASSET RELOCATIONS

Q. What is the purpose of the HVD Asset Relocations sub-program?

A. The overall Asset Relocations Program includes capital investments to relocate assets, as described by Company witness Kelly in his direct testimony. The HVD Asset Relocations sub-program includes the capital investments to relocate 46 kV and 138 kV lines on a reactive basis.

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the HVD Asset Relocations sub-program.

A. The HVD Asset Relocations sub-program includes the capital investments necessary to facilitate non-reimbursable relocations of 46 kV and 138 kV lines required to accommodate usage of public ROW and required transmission project work. The cost of relocating lines in the road ROW, or in some instances on private property, is typically the responsibility of the Company. In other cases, such as relocation work requested by businesses and residential customers, the requesting party will pre-pay or reimburse the Company for the cost of the relocation, but the transactions will still pass through this sub-program.

Q. Which parties typically request HVD Asset Relocations projects?

A. There are four general categories of parties that may request HVD Asset Relocations projects: municipalities and other government agencies, transmission owners, private landowners, and internal Company departments.

Q. Please explain each category of parties that may request HVD Asset Relocations.

A. Municipalities and other government agencies (including the Michigan Department of Transportation ("MDOT")) request HVD Asset Relocations to facilitate their civil engineering projects, such as road and bridge widening and improvements, repairs to municipal facilities, work on water and sewer lines, municipal building and structure construction projects, and streetlight and traffic signal modifications. The HVD Asset Relocations allow those agencies to safely access their facilities without having to work around HVD infrastructure. Relocations may be temporary or permanent.

METC or another transmission owner may request HVD Asset Relocations to accommodate their transmission projects. For example, the Company may have HVD lines attached to METC structures below transmission lines. Depending on the nature of the project, METC may reimburse the Company for associated costs on a case-by-case basis.

Private landowners and businesses request HVD Asset Relocations to accommodate additions, landscaping, and other construction projects on their property. One relatively common request is for overhead lines to be repositioned to allow for building additions.

Internal Company departments may require HVD Asset Relocations to accommodate their own projects they are planning, such as a 2022 project requested by the HVD Planning Department on the National City, Prescott, and Whitestone Point Lines,

where poles were relocated to facilitate the rebuild of the HVD Arenac Substation that is currently underway.

Q. What are some examples of recent HVD Asset Relocations projects?

A. In 2021, the Company relocated four structures on the Grand Valley 46 kV Line in Kent County to accommodate a project by the Kent County Road Commission. The Company also relocated the Millers Point 138 kV line to support MDOT's work to rebuild US-131/KL Avenue bridge in Kalamazoo County in 2023. These examples and others are shown in Figure 67 below.

FIGURE 67
HVD ASSET RELOCATIONS RECENT EXAMPLES

Project Name	Order Created/ Work Completed	Net Capital
Virgina Park Line Relocate Structure 159-166. Requested by Customer.	3/1/2023 – 5/1/2024	$ 237,890
Millers Point 138 kV line. Relocate line to support MDOT rebuild of US-131/KL Ave Bridge. Requested by MDOT.	6/28/18 – 10/02/2023	$ 4,481,153
Upton Line. Relocate Structures 193-199. Requested by customer.	9/9/2021 – 8/19/2022	$ 545,700
Ramona Line. Relocate structures for new I-96 on ramp. Requested by MDOT.	4/13/2021 – 4/15/2022	$ 581,400
Okemos Line. Relocate Structures 1167 and 1168 due to Okemos Road project. Requested by Ingham County Road Commission.	9/26/2020 - 7/14/2022	$ 477,900

Q. How does the Company identify HVD Asset Relocations projects?

A. As discussed above, projects are typically identified by four general categories of parties that may request HVD Asset Relocations projects: municipalities and other government agencies, transmission owners, private landowners, and internal Company departments.

Q. Did the Company consider any alternative approaches for these investments?

A. When an asset must be relocated in this sub-program, there is generally no alternative to doing so. However, each project in this sub-program is evaluated by the HVD Lines Engineering group for the best method of achieving the customer's objective (typically to move the line out of the way of something that will be built in that space), at the lowest cost alternative.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the HVD Asset Relocations sub-program?

A. The Company is projecting HVD Asset Relocations capital expenditures of $1,197,000 in the bridge period, and $899,000 in the test year, as shown in Exhibit A-118 (MPK-8), line 2.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The Commission approved test year spending of $900,000 in Case No. U-21585. The projected bridge period and test year spending in this case is aligned with this approved amount, and it is also closely aligned with actual spending in 2024. In the absence of any pre-identified significant projects in this case for this sub-program, Consumers Energy is projecting to hold investment flat in this sub-program.

Q. What benefits will customers realize through the Company completing work in the HVD Asset Relocations sub-program?

A. The primary purpose of this sub-program is to relocate existing HVD lines at the request of customers, and to fulfill the needs of customers and other external parties, which the Company is required to do. This sub-program also helps improve reliability through the installation of new equipment that meets the Company's current design standards.

Q. Are there any projects that span multiple years?

A. Yes. Since most projects take several months to design and construct, it is common for projects to span from one year into another (see the examples of projects in Figure 67 earlier in this section).

Q. What are the historical costs in this sub-program over the past five years?

A. The historical costs in this sub-program are shown in Figure 68 below.

FIGURE 68
HVD ASSET RELOCATIONS HISTORICAL SPENDING

2020	2021	2022	2023	2024	5-Year Average
$1,906,000	$1,709,000	$2,565,000	$5,319,000	$845,000	$2,469,000

Q. Are any of the costs in the five historical years a significant outlier in this sub-program?

A. In 2023, significant spending occurred as a result of ongoing work to relocate multiple HVD lines for MDOT, with those large projects totaling $4,397,000.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Most projects in this category are customer requested and customer funded. A typical project will be paid for and completed in the same year, resulting in a net-zero spend. Some projects span multiple years, resulting in a credit one year for work performed in another. The remaining projects are those where HVD lines are in the public ROW for which the Company is obligated to cover the cost. There are typically only a few of these projects, but they do range in cost from the single pole relocation for $20,000 to projects like the

current US-131/KL Avenue Bridge rebuild requested by MDOT, for over $4 million. As a result, an average unit cost is not a useful or insightful cost measure in this sub-program.

7. METRO ASSET RELOCATIONS

Q. Please explain what projects, activities, and other types of work will be enabled by the expenditures in the Metro Asset Relocations sub-program.

A. The Metro Asset Relocations sub-program responds to both internal and external requests to relocate or modify civil structures, such as manhole chimneys and castings due to road grade changes, either in a public ROW or on private property, and underground or padmounted electric facilities and service points not related to a new business request. The Company's Metro relocation projects can be on a demand basis or a planned and coordinated basis, with the Company making it a priority to meet mutually agreed upon deadlines and milestones, and to perform the required work within the requested ROW. Projects requested by other departments within the Company may be planned further in advance, rather than on a demand basis.

Q. What is the typical nature of external relocation requests in the Metro Asset Relocations sub-program?

A. External relocation requests come from state agencies, municipalities, downtown development authorities, and private developers. State agencies and municipalities may request relocations to accommodate for upcoming civic improvement work for a specific ROW. Typical improvements include storm and sanitary sewers, water mains, street improvements, and streetscapes. Municipalities, downtown development authorities, and private developers may request relocations to convert overhead electric systems to underground civil and electrical systems, generally to improve aesthetics. These requests typically require the customer to provide a non-refundable engineering deposit for the

Company to perform a feasibility study to find an underground path for the civil infrastructure system.

Q. Does the Company request reimbursement for a Metro relocation request?

A. Yes, the Company seeks reimbursement for a third-party initiated Metro relocation request on a case-by-case basis. Commonly, reimbursement is sought when a third party requests the existing overhead distribution system be converted to underground. The same process applies to those third parties requesting a vacation of the ROW—the Company will seek reimbursement to convert existing overhead distribution to underground distribution, and seek a permanent easement from the new property owners of the vacated ROW.

Q. Does reimbursement match the cost of relocation?

A. Yes, when the Company establishes reconcilable contracts with the requesting third party, the Company will either credit or invoice the requesting party at the end of the project for its actual costs for the conversion of overhead distribution to underground metro distribution.

Q. What is an example of a recent externally requested Metro Asset Relocations project?

A. The Company and the City of Saginaw are engaged in a two-year coordination of utilities agreement allowing the Company to expand its metro facilities in the Water Street ROW. The project is in coordination with the City of Saginaw and Saginaw Future to make the site ready for the planned Saginaw Medical Diamond development. The Saginaw Medical Diamond will include medical offices and education, mixed use residential, and retail.

At the request of the City of Kalamazoo, the Company delayed the start of its coordination of utilities project, to rebuild its metro facilities in the Kalamazoo Avenue ROW to 2026. This project is the first of many the City of Kalamazoo Public Works

department has identified to transform its one-way street network back to two-way traffic flows in Downtown Kalamazoo.[2] The City is presently in preliminary design for its Michigan Avenue street conversion, in which Consumers Energy will also seek to rebuild its aging infrastructure in a coordination of utilities fashion with engineering starting in 2026.

Q. What is the Company's process for planning Metro Asset Relocations projects in response to internal requests?

A. Projects triggered by an internal request are considered during the Metro planning process, which takes place in July and August of each year. Company engineering planners, with responsibility for planning and design of the affected Metro system area, prepare scope documents and estimated project costs during this process. Internal requests are triggered by various workgroups, such as Substation Planning, LVD Planning, or HVD Planning. An example of an internal request is in Jackson, where Substation Planning plans to replace the Ingham Substation transformer bank (refer to Exhibit A-109 (MLH-3), page 5, line 14). Metro will support this project by converting its electrical vaults from delta operations to grounded wye and reconfigure the primary circuits for better substation loading and performance.

Q. What benefits will customers realize through the Company completing work in the Metro Asset Relocations sub-program?

A. Although the primary purpose of this sub-program is to accommodate the needs of customers and other external parties, the sub-program does help improve reliability through the installation of new equipment. When the Company replaces old or obsolete equipment

[2] https://www.kalamazoocity.org/News-articles/Kalamazoo-Avenue-Two-Way-Plans-will-be-Introduced-at-May-Meetings

with new equipment as part of a relocation project, reliability is improved since the new equipment has up-to-date design standards and less general wear and tear. Customers connected directly to these assets receive these reliability benefits.

Q. Please identify the projects that will be accomplished with the requested spending level in the Metro Asset Relocations sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-109 (MLH-3), page 13, and for the test year, listed in Exhibit A-110 (MLH-4), page 13. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the location of the projects.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Metro Asset Relocations sub-program?

A. The Company is projecting Metro Asset Relocations capital expenditures of $16,094,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 40, column (k), and $20,405,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 40, column (l). The Company's historical actual spending in the Metro Asset Relocations sub-program, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 40.

Q. What is driving the Company's projected increase in investment in Metro Relocations?

A. The Company's spending in the Metro Asset Relocations sub-program is based on external requests, and therefore varies from year to year based on the requests that the Company receives. In the instant case, the Company is addressing more requests than in recent years, tied to municipal projects in Grand Rapids, Saginaw, and Kalamazoo. The associated

identified Metro Relocations projects determine the amount of investment needed for this sub-program.

Q. How did the Company develop its projected bridge period expenditures?

A. The Company has identified relocation projects in Exhibit A-109 (MLH-3), page 13, that supports the bridge period spending level, and projected expenditures are based on these projects.

Q. How did the Company develop its projected test year expenditures?

A. The spending amount for the test year is supported based on three municipal projects planned for 2026 and early 2027, each of which require Metro Relocations work.

First, Kalamazoo Avenue in the City of Kalamazoo will be reworked, and the Company will coordinate with the City's engineering department. The Company will be installing new Metro infrastructure to replace its aging system within the ROW, and provide service to new Company-owned streetlighting and traffic signal services to new city traffic signals at various intersections.

The second project is the Front Avenue ROW modifications in the City of Grand Rapids. The Company is replacing its Metro assets along Front Avenue in coordination with ROW modifications by the City of Grand Rapids for the Grand Rapids Public Museum expansion, a Grand Valley State University project, and modification of pedestrian flow in the area.

The third project is an internal request to accommodate a large duct bank for the future Quicksilver LVD substation located on Wealthy Street west of Front Avenue (refer to Exhibit A-110 (MLH-4), page 10, line 8. This duct bank and substation will support the growth and development in and around the Acrisure Amphitheater, Amway Soccer

Stadium, and Grand Valley State University's Blue Dot project and long range facilities plan for the Pew Campus expansion.

Q. Are there any projects that span multiple years?

A. Yes, due to the size and scope of some Metro Asset Relocation projects, it is common for the civil assets to be installed in one year with the electrical assets installed in the year following. The Kalamazoo Avenue project, listed in Exhibit A-110 (MLH-4), page 13, lines 7 and 8, is a multi-phase project in which construction will span from 2026 to 2027. The Quicksilver substation duct bank support project will also span a number of years. These project timelines may be adjusted if future construction or permit barriers are experienced.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Investment in this sub-program depends heavily on the volume and complexity requests for relocation. Most recent years have set new levels of investment. Continued growth in these metro areas are expected to sustain a need for higher-than-average capital expenditures in this sub-program.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Average unit cost is not a good measure of spending to predict the cost of an individual project in this sub-program. There is a wide variance of scale and scope among the work required.

VII. LINE CATEGORIZATION

Q. Please discuss Exhibit A-111 (MLH-5).

A. Exhibit A-111 (MLH-5) documents how the Company categorized substation and HVD line distribution assets for the EAC report. The EAC report utilized by COSS to break out certain distribution assets and related costs into greater detail.

Q. How were substation assets categorized in the EAC report?

A. The Company's engineering personnel reviewed substation drawings and engineering records to assign substation assets to each EAC report category. The substation categories in the EAC report, listed below, capture both the high side asset voltage (138 kV or 69-46kV) and the voltage level of downstream facilities (either V1, V2, V3 and/or V4)[3] connected to/relying on that substation:

- 138 kV (V1) Bulk Power Substations (Shared: V2,3,4)
- 138 kV (V1) Distribution Substations (Shared: V3,4)
- 138 kV (V1) Substations (V1 Only)
- 69-46 kV (V2) Bulk Power Substations (Shared: V2,3,4)
- 69-46 kV (V2) Distribution Substations (Shared: V3,4)
- 69-46 kV (V2) Substations (V2 Only)
- GSU Substations (Production)
- Other Equipment and Facilities

Substations that serve generation were categorized as GSU or Generation Step Up. Substations serving a single, dedicated customer were categorized as either 138 kV or 69-46 kV V1 or V2 Only depending on the customer's voltage level. Substations serving multiple customers through primary distribution (e.g. distribution substations) were

[3] Where V1: 138 ≥ X > 120; V2: 120 ≥ X > 25; V3: 25 ≥ X > 2.4 and V4: 2.4 kV or less.

categorized as either 138 kV or 69-46 kV "Shared: V3, V4" as appropriate. Where a substation serves multiple categories, the Company calculated the appropriate weighting by reviewing and categorizing the major assets within the substation, focusing on major equipment including transformers, voltage regulators, breakers, and bulk capacitors. For example, if a substation contains a transformer that serves a single, dedicated customer (V2) and a second transformer that serves only primary distribution, that substation is 50% V2 and 50% V3, V4. Or, if a substation contains a 138 kV breaker (V2), a 138/46 kV transformer (V2), two 46 kV breakers (V2), and a 46 kV/Distribution transformer (V3, V4) that substation is 20% V3, V4 and 80% V2.

Q. How were HVD line assets categorized in the EAC report?

A. The Company's engineering personnel reviewed the HVD lines and assigned them to the EAC report categories. The EAC report categories, listed below, capture the line type (overhead or underground), energized voltage level (138 kV or 69-46 kV) and the voltage of downstream facilities (either V1, V2, V3 and/or V4) connected to/relying on that line.

Overhead ("OH") Lines:

- 138 kV (V1) OH Lines (Shared: V1, 3, 4)
- 138 kV (V1) OH Lines (Shared: V3, 4)
- 138 kV (V1) OH Lines (V1 Only)
- 69-46 kV (V2) OH Lines (Shared: V2, 3, 4)
- 69-46 kV (V2) OH Lines (Shared: V3, 4)
- 69-46 kV (V2) OH Lines (V2 Only)
- GSU OH Lines (Production)
- Other Equipment and Facilities

Underground ("UG") Lines:

- 138 kV (V1) UG Lines (V1 Only)
- 69-46 kV (V2) UG Lines (Shared: V2, 3, 4)
- 69-46 kV (V2) UG Lines (Shared: V3, 4)
- 69-46 kV (V2) UG Lines (V2 Only)
- GSU UG Lines (Production)
- Other Equipment and Facilities

Lines that serve only a generation substation were categorized as OH or UG GSU or Generation Step Up. Lines serving only a dedicated customer substation were reviewed and categorized according to the asset type (OH or UG), energized voltage level, and included as either V1 or V2 Only depending on the dedicated customer's voltage level. Lines serving only a distribution substation were categorized as Shared:V3, V4. If the line serves multiple generation, dedicated customer, and/or distribution substations, the common section of the line was categorized as shared between the voltage categories of the downstream substations served from that section of the line.

For example, a line section directly connected to the source transmission line, down to the first junction point where it branches off to serve multiple substations is categorized as "V1, V3, V4" or "V2, V3, V4" based on the line voltage and the category of substations connected to it. From the junction point, if a generation substation is connected at the end of that line section, that section of line is categorized as Generation; if a dedicated customer substation is connected at the end of that line section, that section of line is categorized as V1 or V2; and if a distribution substation is connected at the end of that line section, that section of line is categorized as "V3, V4".

To give another example, in the case where the line section is directly connected to the source 46 kV line, the line section up to the first junction point where it branches off to serve the substation, is categorized as "V2, V3, V4" based on the line voltage. From the junction point, if a generation substation is connected at the end of that line section, that section of line is categorized as Generation; if a dedicated customer substation is connected at the end of that line section, that section of line is categorized as V2; and if a distribution substation is connected at the end of that line section, that section of line is categorized as "V3, V4".

VIII. SUMMARY

Q. Please provide a brief overview of your testimony and the intent of investing in HVD capital programs to support the Company's electric distribution system.

A. My testimony has provided an overview of the HVD system and associated capital investments to improve reliability and resiliency of the system while serving new customers to support economic development in the state of Michigan. The testimony provided detail of each HVD capital investment program, the basis of planned investments, and benefits. All HVD capital investments outlined in my testimony are identified and planned to support the overall objectives and strategy outlined in the Company's Reliability Roadmap. My testimony highlighted increased spending in several areas in order to meet the reliability and asset health goals defined in the Reliability Roadmap.

As supported throughout my testimony, the Company's projected HVD capital expenditures are summarized in Figure 69 and should be approved by the Commission.

FIGURE 69

HVD CAPITAL EXPENDITURE SUMMARY

	Bridge Period	Test Year
All Programs	$524,846,000	$417,546,000

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

MEGAN L. HAYWARD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Megan L. Hayward, and my business address is 1945 W Parnall Rd, Jackson, Michigan 49201.

Q. Are you the same Megan L. Hayward who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Ally Durfee; Attorney General witness Sebastian Coppola; and Association of Businesses Advocating Tariff Equity ("ABATE") witnesses Jessica A. York and Colin T. Fitzhenry.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-218 (MLH-6) Discovery Response 21870-AG-CE-0466.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

I. REBUTTAL OF STAFF WITNESS DURFEE

Q. Do you have any overall comments on Ms. Durfee's analysis of and recommendations regarding the Company's projected High Voltage Distribution ("HVD") capital investments?

A. In each of the HVD capital sub-programs where Ms. Durfee recommends a disallowance, she does so on the basis of (a) reviewing the Company's year-to-date spending through June 2025 in the relevant sub-program; (b) translating that spending into a percentage of

the Company's filed projection for the 2025 calendar year, as shown in Exhibit A-95 (MPK-3); (c) assuming that the average monthly spending for the first six months of 2025 will be carried forward into the future on a linear basis; and (d) recommending bridge period and test year disallowances based on the differences between the Company's filed projections and the amounts implied by those linear projections.

Q. Are there any flaws with this approach?

A. Yes. I will address Ms. Durfee's analysis of each sub-program separately, but it is important to note that many HVD capital sub-programs will not have a consistent month-by-month spending level, nor can future spending levels be projected linearly based on a short-term amount of data. Many HVD projects, particularly in substations, require temporary system reconfigurations in order to deenergize certain components while not interrupting any customers. Because of this, many types of HVD projects can only be undertaken during certain parts of the year. This can be due to weather, electric load conditions, or other limitations that impact when system reconfigurations are needed before the work can be undertaken. Furthermore, many HVD projects are large and complex and therefore may not have closely similar spending levels each and every month.

Q. What is Ms. Durfee's recommendation regarding the HVD Substations Reliability sub-program?

A. On page 6 of her direct testimony, Ms. Durfee calculates that, through June 2025, the Company only spent a fraction of what would be needed to be on track to spend its full 2025 calendar year projection. Staff witness Durfee assumes a linear monthly spending level to project how much she believes the Company will actually spend in 2025 and then

uses that amount to recommend disallowances not only for 2025, but also on a prorated basis for the first four months of 2026 and for the entire test year.

Q. Do you agree with this recommendation?

A. No, I do not agree with the dollar value that Ms. Durfee is recommending for disallowance. Since the time the Company provided year-to-date actuals through June 2025 in discovery in this case, the Company has been reevaluating the feasibility of its projected spending levels for HVD Substations Reliability. This reevaluation is consistent with Ms. Durfee's approach to this sub-program of evaluating how much is likely to be invested, although the Company was completing this evaluation prior to Ms. Durfee filing her testimony.

Many projects in the HVD Substations Reliability sub-program require full or partial substation planned outages in order to affect the system reconfigurations described above, for the safety of the crews performing the work. Because HVD substations are large backbone pieces of the Company's entire system, with large numbers of customers served by each one, the Company can only take these partial substation outages in significant numbers at certain times of the year. Most notably, the Company is limited in how many outages it can take on HVD substations during the summer, when loads are high and therefore the Company cannot easily transfer load to alternative substations.

The Company's 2025 projected investment was based on the Company's proposed spending in Case No. U-21585. The Order in that case, and therefore the Commission's approval for that spending, was received on March 21, 2025. This was only a handful of weeks before the onset of warmer weather and higher loads, which limited the Company's ability to fully invest through the end of June.

The Company has now reevaluated its plan for the remainder of the bridge period, and the Company projects that its total bridge period investment will be $22,230,000 for the HVD Substations Reliability sub-program, as shown in Exhibit A-219 (MPK-29), line 4. Rather than the full disallowance level recommended by Ms. Durfee, the Commission should approve that amount for the bridge period, which would translate into a disallowance of $10,992,000 for the portion of the bridge period ending on December 31, 2025. This is a reduction from the Company's requested 2025 bridge period amount, and is driven by an unseasonably warm fall that has further prevented the Company from taking the requisite outages to safely conduct the planned work. Additionally, the Commission should not approve Ms. Durfee's disallowance for the test year. Given the experiences from the unseasonably warm weather experienced in 2025, the Company is developing contingencies if this weather pattern recurs in the future in order to ensure all planned work can be completed. The Company will do this primarily by focusing increasing work in the earlier months of the year preceding warmer weather.

Q. What is Ms. Durfee's recommendation regarding the Transformer Bank Replacement and Substation Rebuilds sub-program?

A. On page 7 of her direct testimony, Ms. Durfee calculates that, through June 2025, the Company only spent a fraction of what would be needed to be on track to spend its full 2025 calendar year projection. She assumes a linear monthly spending level to project how much she believes the Company will actually spend in 2025 and then uses that amount to recommend disallowances not only for 2025, but also on a prorated basis for the first four months of 2026 and for the entire test year.

Q. Do you agree with this recommendation?

A. No. As with HVD Substations Reliability, the Company faced limitations over the summer and into the early fall in its ability to take needed planned outages. Additionally, many of the projects in this sub-program are very large and come with permitting requirements, and the Company faced permitting delays earlier this year. For example, the Buskirk Creek rebuild project (see Exhibit A-109 (MLH-3), page 3, line 9) was delayed in receiving a necessary permit from the Department of Environment, Great Lakes, and Energy earlier in 2025, causing an approximately two-month shift in the project schedule and causing over $4 million in investment to be shifted from 2025 to 2026. These factors combined to cause year-to-date spending through June to be lower than projected.

Q. Has the Company recently evaluated its projected spending for Transformer Bank Replacements and Substation Rebuilds?

A. Yes. The Company continues to forecast that it will be able to catch up and achieve the full projected bridge period amount, as shown in Exhibit A-219 (MPK-29), line 6. This will be achieved primarily through scheduling a greater portion of planned work in the earlier part of the year preceding the warmer months, as well as ramping up work again when it is cooler later in the year. Therefore, Ms. Durfee's recommended disallowance should not be adopted for the bridge period. Furthermore, since the Company will spend at its projected bridge period level, Ms. Durfee's logic for a test year disallowance is no longer relevant, and the Commission should not approve her recommended test year disallowance.

Q. What is Ms. Durfee's recommendation regarding the Metro Rehabilitation sub-program?

A. On pages 8 and 9 of her direct testimony, Ms. Durfee calculates that, through June 2025, the Company only spent a fraction of what would be needed to be on track to spend its full 2025 calendar year projection. She assumes a linear monthly spending level to project how much she believes the Company will actually spend in 2025 and then uses that amount to recommend disallowances not only for 2025, but also on a prorated basis for the first four months of 2026 and for the entire test year.

Q. Do you agree with this recommendation?

A. No. Although spending in the first half of 2025 may have been lower than projections would indicate, the Company's updated spending and forecast shows that the Company's spending projection are still reasonable. Refer to Exhibit A-219 (MPK-29), line 7. Metro Rehabilitation work consists of crushed concrete-encased duct bank replacement and manhole rehabilitation. These types of projects are primarily executed once frost has receded. Therefore, investments are frequently skewed towards the later part of the year. The Company's forecasted investments in Metro Rehabilitation for 2025 are still close to those projected in the Company's filing, with increases based on two projects actively in construction and one project with bidding activities for construction completed. Therefore, Ms. Durfee's recommended disallowance should not be adopted for the bridge period. Furthermore, since the Company will spend at its projected bridge period level, Ms. Durfee's logic for a test year disallowance is no longer relevant, and the Commission should not approve her recommended test year disallowance.

Q. What is Ms. Durfee's recommendation regarding the System Control Projects sub-program?

A. On page 10 of her direct testimony, Ms. Durfee calculates that, through June 2025, the Company only spent a fraction of what would be needed to be on track to spend its full 2025 calendar year projection. She assumes a linear monthly spending level to project how much she believes the Company will actually spend in 2025 and then uses that amount to recommend disallowances not only for 2025, but also on a prorated basis for the first four months of 2026 and for the entire test year.

Q. Do you agree with this recommendation?

A. No. Although spending in the first half of 2025 may have been lower than projections would indicate, the Company's projections, especially for 2026 and 2027, are still reasonable reflections of likely spending amounts. The history of this sub-program, as shown in Exhibit A-95 (MPK-3), line 44, shows that spending has been somewhat variable from year to year. Most notably, the Company's actual spending in 2024 was $896,000. In other parts of the instant case, Staff uses 2024 actuals as a proxy for what the Company is apparently capable of investing; Ms. Durfee does not rely on this logic, but Staff witness Ryan Boutet does so in his analysis of Low Voltage Distribution ("LVD") Zonal Health Improvement projects, for example.

In the instant case, the Company is projecting to invest much less in System Control Projects than it did in 2024. This indicates that the Company is capable of investing at projected levels, and Ms. Durfee's proposed disallowance should not be adopted.

Q. What is Ms. Durfee's recommendation regarding the LVD Substations Demand Failures sub-program?

A. On page 11 of her direct testimony, Ms. Durfee notes that the unit costs for transformers have overall been steady or declining from 2020 through 2024, and that the average cost was approximately $700,000. The Company's projected unit cost, as derived from Figure 66 in my direct testimony, is $845,000. Ms. Durfee recommends a disallowance based on the difference between this cost and the historical average.

Q. Do you agree with this recommendation?

A. No. Ms. Durfee states that she has calculated a five-year average unit cost of $700,000 based on the data presented in Exhibit A-130 (MPK-20). However, the average cost is actually higher than this. Exhibit A-130 (MPK-20), page 2, line 30, shows that the Company spent $13,357,103 over five years on 18 transformers in this sub-program, which yields an average of $742,061. But beyond that, transformer unit costs are still generally increasing, as shown by recent market data. During the latter part of 2024, the Company made purchase orders based on competitive bids for transformers, with 33 similar sized transformers costing an average of $812,000, indicating a recent increase. This supports the Company's projected bridge period and test year unit costs, and Ms. Durfee's recommendation for disallowance should not be adopted.

Q. What is Ms. Durfee's recommendation regarding the Metro Demand Failures sub-program?

A. On page 12 of her direct testimony, Ms. Durfee calculates that, through June 2025, the Company only spent a fraction of what would be needed to be on track to spend its full 2025 calendar year projection. She assumes a linear monthly spending level to project how

much she believes the Company will actually spend in 2025 and then uses that amount to recommend disallowances not only for 2025, but also on a prorated basis for the first four months of 2026 and for the entire test year.

Q. Do you agree with this recommendation?

A. No. Like other sub-programs in the Demand Failures Program, the Metro Demand Failures sub-program is based on emergent needs that the Company must address quickly after they arise. Because of this, projected Demand Failures investments are usually heavily based on historical actuals, which provide a good proxy of what will likely be needed in the near-term future. Considering the Company's history in the Metro Demand Failures sub-program, as shown in Exhibit A-95 (MPK-3), line 36, historical actual spending has come in on both sides of the historical average of $339,000. That historical average, encompassing five years of data, is a much better indicator of likely needs through the rest of the bridge period and the test year than simply looking at six months of data. The Company's test year projection is closely aligned with the five-year average and should be approved by the Commission. The Company's bridge year projection is also reasonably close to the historical average, but if the Commission does authorize a bridge period disallowance, it should only do so in such a way that bridge period spending will also be aligned with the five-year average, instead of the much lower amount recommended by Ms. Durfee.

II. <u>REBUTTAL OF ATTORNEY GENERAL WITNESS COPPOLA</u>

Q. What is Mr. Coppola's recommendation regarding the LVD Substations Rehabilitation sub-program?

A. On page 48 of his direct testimony, Mr. Coppola observes that the Company is planning to increase its rate of replacing Allis Chalmers transformers in order to complete the

replacement of all remaining units by the end of the test year. Mr. Coppola recommends that the Company moderate the impact on rates by spreading this work out over four years, and proposed a disallowance based on the resulting reduction in bridge period and test year work.

Q. Do you agree with this recommendation?

A. No. Allis Chalmers transformers have a long-documented history of issues, and the Company's approach in the instant case is based on finally resolving this ongoing matter. The Company should not drag the process out further, and the Commission should approve the Company's projection.

Furthermore, the Company's bridge period projections were made by taking into account the Commission's approved spending levels from Case No. U-21585. During the bridge period, which is already in its tenth month, the Company has been making investments in line with what the Commission previously found to be reasonable and prudent. If the Commission does not agree with the Company's plan to finish Allis Chalmers transformer replacements in the test year in the instant case, it should not adopt any bridge period disallowances, and any lengthening of the Company's plan to complete the replacements should apply to the test year only.

Q. Does Mr. Coppola have other recommendations regarding LVD Substations Rehabilitation?

A. On pages 49 and 50 of his direct testimony, Mr. Coppola argues that the Company has not substantiated its increased unit costs for the Equipment Replacement and Regulatory investment category, and proposes a disallowance based on this. He further notes that the

Company is planning an increased number of projects in the bridge period and test year, and proposes to hold the number of projects at the three-year historical average as well.

Q. Do you agree with this recommendation?

A. No. Regarding unit costs, page 92, line 13, through page 93, line 12, of my direct testimony makes clear that this investment category includes a diverse range of project types, and unit costs can vary accordingly based on project specifics (see also page 91, lines 11 through 15). Furthermore, page 93, lines 13 through 19, of my direct testimony indicates that a number of projects span multiple years, which skews the ability to calculate year-by-year unit costs since project costs may not have uniformity across the duration of the project. Exhibit A-109 (MLH-3), page 5, indicates that bridge period projects range from $149,000 to $1,485,000. Exhibit A-110 (MLH-4), page 5, indicates that test year projects range from $330,000 to $3,381,000. This indicates that individual projects are variable enough in this investment category that unit cost analysis is not appropriate.

Regarding the number of units itself, Mr. Coppola offers no reason at all for why the Company should be held to the three-year average. Given the lack of reasoning, this recommendation should also be rejected by the Commission. As with Allis Chalmers transformer replacements, I note that the Company has been making bridge period investments for several months in line with what the Commission previously found reasonable and prudent in Case No. U-21585, and the Commission should not make any bridge period disallowances that would negatively impact work already done under the Commission's prior authorization.

Q. What is Mr. Coppola's recommendation regarding the LVD Substations Capacity sub-program?

A. On page 51 of his direct testimony, Mr. Coppola indicates support for the Company's New Substations projection in the bridge period, but he states that the Company's projection of 11 New Substations in the test year is excessive since this is a greater number than the Company has done recently. He proposed a disallowance based on keeping the Company's units at constant levels.

Q. Do you agree with this recommendation?

A. No. As stated on page 132, lines 9 through 12, of my direct testimony, I explained how projects are identified based on identified capacity needs and work to mitigate planning criteria violations. Since the number of projects is dependent on pockets of local load growth, the number can vary from year to year. Each of the 11 test year projects in this case have been identified as necessary to prevent system overloads due to local load growth. Mr. Coppola's recommendation, if followed, would result in the Company irresponsibly ignoring known load growth pockets on its system, increasing overload risk.

Q. Does Mr. Coppola have any other recommendations regarding LVD Substations Capacity?

A. On page 52 of his direct testimony, Mr. Coppola takes issue with the Company's projection for growth in the Existing Substations investment category, finding that the Company has not provided specific supporting information. He cites discovery response 21870-AG-CE-0477, which he has included as Exhibit AG-11, stating that it did not provide sufficient information to justify why the Company's bridge period projects are all necessary. Based

on this, he recommends holding the number of projects at recent historical levels, with associated bridge period and test year disallowances.

Q. Do you agree with this recommendation?

A. No. In discovery request 21870-AG-CE-0477c, the Attorney General asked the Company, "For the existing substation projects, identify what problems are being addressed and at which existing locations." In response, the Company explained that my direct testimony already describes what problems are being addressed by these projects and Exhibits A-109 (MLH-3) and A-110 (MLH-4) already identify the locations. Mr. Coppola laments that the Company's response did not identify overload levels, but this was not asked for in the discovery request. The Company can only answer the questions it is asked; it cannot guess what specific data points are sought if the request does not indicate what they are. In this instance, the Company answered the question that was asked. It is arbitrary for Mr. Coppola to then argue that the Company did not provide a type of detail that has not been sought by any party.

Finally, I will note that LVD Substations Capacity is another sub-program in which the Company has been making bridge period investments for several months in line with what the Commission found reasonable and prudent in Case No. U-21585, and the Commission should not make the substantial bridge period disallowances sought by Mr. Coppola that would affect work already done under the Commission's prior authorization.

Q. How does Mr. Coppola address the HVD lines system?

A. On page 53 of his direct testimony, Mr. Coppola states that the Company's HVD system is "in much better shape" than its LVD system, based on the relative level of HVD-caused

outages compared to LVD-caused outages. He surmises that a short line clearing cycle and a base level of capital improvements is sufficient for the HVD system, and that increases in HVD capital are not needed "across the board." He says he will bring this critical eye to the Company's HVD lines and substations investments in the instant case.

Q. How do you respond to this?

A. As I discuss at length in my direct testimony, the Company's HVD lines and substations investment are heavily driven by asset health assessment in order to maintain the system's redundancies that are designed to prevent large-scale HVD outages from happening in the first place. See in particular pages 12 through 19 of my direct testimony, with the conclusion on page 19, line 11, through page 20, line 2, regarding the consequences of not investing in the HVD system at proposed levels. Despite the HVD system's share of total System Average Interruption Duration Index ("SAIDI"), it is still critical to invest in improving it in order to maintain it as the backbone of the system.

Q. What is Mr. Coppola's recommendation regarding HVD line rebuilds in the HVD Lines Reliability sub-program?

A. On page 54 of his direct testimony, Mr. Coppola supports the Company's bridge period plan for HVD line rebuilds, but argues that the test year work volume is too high, as it represents a 50% increase from the highest volume year in recent history. He recommends that the test year workplan be limited to 40 miles, and proposes a disallowance based on this.

Q. Do you agree with this recommendation?

A. No. It is an inexact process of determining the actual number of miles of HVD line rebuilds in a given year. The Company's practice has been to count miles toward the year that the

project is complete, and this can make there appear to be dramatic variation in year-over-year work levels even when the Company is completing fairly equivalent amounts of work from year to year. As shown in Exhibit A-109 (MLH-3), page 1, there are eight bridge period HVD line rebuild projects that will carry over beyond the bridge period, and therefore count as zero miles for the bridge period in the total in Figure 21 of my direct testimony. As shown in Exhibit A-110 (MLH-4), page 1, these projects will be completed during the test year, which means all those miles are recorded in the test year in Figure 21 as well. Meanwhile, the test year only has three projects that are carried forward into the next year. In short, while Figure 21 contains mileage numbers that imply a large increase in work volume in the test year, this is not actually what is happening. If one considers the dollar amounts for the bridge period and the test year in Figure 21, they indicate a relatively flat amount of work rather than a dramatic increase.

The Company's bridge year projection in the instant case is informed by what the Company proposed and what the Commission approved in Case No. U-21585. The test year in the instant case is meant to essentially be a continuation of that work level. The only thing obscuring this is the misalignment in miles reported for each year, for the reasons given above. As shown by the projected investment levels, the Company's test year plan is simply a continuation of what the Commission approved in Case No. U-21585. For this reason, Mr. Coppola's recommendation, premised on the idea that the test year represents a major increase in work, should be rejected.

To make another point, the discussion above highlights how many projects carry over from year to year, since they can be large in scope. This means the Company relies on consistent funding levels from year to year to keep projects on track and ensure they

can actually be completed. If the Commission orders the Company to reduce its test year spending, and therefore its test year work, by approximately 40% as Mr. Coppola suggests, then the Company will be impaired in its ability to complete bridge year projects already underway in alignment with the Commission's Order in Case No. U-21585.

Q. What is Mr. Coppola's recommendation for pole top rehabilitation projects in the HVD Lines Reliability sub-program?

A. Mr. Coppola presents his argument on page 55 of his direct testimony, and it is essentially the same as his argument for HVD line rebuilds: that the bridge period appears reasonable, but that the test year represents a stark increase in work. He recommends a similar disallowance based on limiting the test period work level to recent actual levels.

Q. Do you agree with this recommendation?

A. No. My response is essentially the same as my response to Mr. Coppola regarding HVD line rebuilds, namely that much of the apparent variation in miles from year to year is due to the Company's practice of recording all the miles in the year that the project is completed. Mr. Coppola's recommendation should be rejected for the same reasons given in my discussion of HVD line rebuilds.

Q. What is Mr. Coppola's recommendation regarding HVD pole replacements?

A. On pages 56 and 57 of his direct testimony, Mr. Coppola notes that the Company's projected increase in work is driven by a need to address a backlog of red-tagged poles, and he reviews the data provided by the Company in discovery on the development of this backlog since 2016. Mr. Coppola avers that it would be unduly burdensome to completely clear the backlog by 2027 as the Company proposes, and he recommends spreading this

process over five years instead. He calculates proposed bridge period and test year disallowances based on the difference between the two replacement rates.

Q. Do you agree with this recommendation?

A. No. In discovery request 21870-AG-CE-0465a, the Attorney General asked the Company to "Explain why the Company built a backlog of 2,250 poles and did not address the replacement of those poles timely in prior years." In response, the Company reminded the Attorney General that the reduction of the pole backlog is in alignment with the recommendations set forth in the MPSC's audit report. Furthermore, poles are red tagged because they have reached an unacceptable state of deterioration. As referenced in 21870-AG-CE-0465a, the Company's past practices of integrating individual pole replacements into larger projects has been a factor in the increase of the backlog, but this does not change the fact that these poles are in fact deteriorated and present a risk to both safety and reliability if they fail. Allowing a significant number of red-tagged poles to remain on the system for up to two additional years simply increases or extends that risk to the public, to employees, and to reliability.

Q. What is Mr. Coppola's recommendation regarding the Circuit Breakers investment category in the HVD Substations Reliability sub-program?

A. On page 59 of his direct testimony, Mr. Coppola states that the Company's recent average level of circuit breaker replacements was 17 per year, and he argues that there is no justification for why this work volume increases substantially in the bridge period and test year. He also argues that unit costs increase by too much from the bridge period to the test year with no explanation. He recommends disallowances based on holding the Company

to 40 circuit breaker replacements per year, approximately double the Company's recent level, and holding unit costs at recent levels plus inflation.

Q. Do you agree with this recommendation?

A. No. Please note that, in my rebuttal to Ms. Durfee, I have already conceded some of the Company's overall proposed investment level in the HVD Substations Reliability sub-program, but Mr. Coppola's total recommended disallowances for the sub-program are greater.

The recent levels of circuit breaker replacements predate the Company's development of the Reliability Roadmap, which was published in September 2023, and which first began to actually impact investment levels in 2025. The Reliability Roadmap included a thorough review of HVD substation asset health, which led to the conclusion that the Company needed to increase investment in replacing various substation components, including circuit breakers. This is included in Figure 109 in Exhibit A-129 (MPK-19).

Mr. Coppola's proposed disallowance is further premised on his claim that the Company provided "no specific explanation" for why the Company must replace more circuit breakers. But this is not true. Page 62, line 10, through page 63, line 5, of my direct testimony explains the issues with circuit breakers, namely that many of them are now severely obsolete, are in poor asset health, and replacement parts are scarce. The situation is similar to that discussed above in my rebuttal regarding LVD Substation Capacity: Mr. Coppola asserts that the Company has not been specific without any reference to details that the Company did provide and gives no indication of what an appropriate level of specificity would be.

Q. What is Mr. Coppola's recommendation regarding the "Other/Miscellaneous" investment category in the HVD Substations Reliability sub-program?

A. On page 60 of his direct testimony, Mr. Coppola argues that the Company did not provide any specific justification for its projected work volume in this investment category, and he recommends disallowances that would limit the Company's investment level to double the recent actual level.

Q. Do you agree with this recommendation?

A. No. Once again, Mr. Coppola says the Company has not provided enough specific information without ever saying what the requisite level of specificity is. The Company's plan for the "Other/Miscellaneous" investment category is on a similar trajectory to that of Circuit Breakers, with an increase from recent levels driven by the review of asset health that started with the Reliability Roadmap; in fact, the Company provided this explanation in discovery response 21870-AG-CE-0469, which has been provided as Exhibit AG-13. Part of Mr. Coppola's criticism appears to be based on the Company's response to 21870-AG-CE-0469b, in which the Attorney General asked about the "Other/Miscellaneous" investment category. This question asked, "Identify expenditures of $1 million or greater in Other and explain what they entail for the bridge period and projected test year." The Company's response explained this in an appropriate amount of detail. In no other place does the Attorney General ask further questions or even engage with the level of detail provided by the Company.

Q. What is Mr. Coppola's recommendation regarding so-called "premature projects"?

A. In discovery, the Attorney General asked the Company to provide a list of HVD projects that exceed $3 million, and to provide information on the current development level of the

project. The Company did so, and Mr. Coppola has provided this as Exhibit AG-14. Mr. Coppola's ultimate conclusion is that the large majority of such projects are at a stage where he calls them "premature" for inclusion in rate base, and he recommends their disallowance.

Q. How do you respond to this?

A. The reasonableness of Mr. Coppola's recommendation varies depending on which projects he is assessing. Considering the bridge period first, he notes that two projects, both in the HVD Strategic Customers New Business sub-program, have been cancelled, and he recommends their disallowance. Although it would normally be reasonable to remove money allocated for cancelled projects, the HVD Strategic Customers New Business sub-program is unique in that the Company enters into contracts with customers to perform projects, and executes work based on those agreements with customers. In the event that a project is cancelled because of customer action (or inaction), the investments were still reasonable and prudent at the time they were made. In this sub-program, actual costs already incurred for these projects should not be disallowed. See my rebuttal to ABATE witnesses York and Fitzhenry for further discussion of this issue.

Mr. Coppola states that the $7,349,000 in the HVD Strategic Customers New Business sub-program for High Probability Projects is a placeholder amount, which the Commission has ruled should be excluded from rate base. But that is not true in this instance. In Case No. U-21585, the Commission ruled that it was reasonable and prudent for the Company to strategically procure critical inventory designed to make it easier to execute on high-probability projects in this sub-program when they arise. The Company's projected investment in the bridge period is consistent with the Commission's decision.

Finally, at page 63 of his direct testimony, Mr. Coppola notes that two other projects in the Transformer Bank Replacement and Substation Rebuilds sub-program are "still in the early phase of development, and it is uncertain if and when they will be completed and at what specific cost," and he believes they should be disallowed. Here, Mr. Coppola has not fully understood the two projects in question. The Alma and Blackstone substation rebuild projects are multi-year projects. As Exhibit AG-13 shows, they will not be fully complete with construction until 2028 or 2029. But Exhibit AG-13 also shows that property acquisition is already ongoing for these projects, meaning capital costs are already being incurred. Both of these projects were included in the Company's proposal in Case No. U-21585 in what was then called the HVD Lines and Substations Rehabilitation sub-program; the Commission's Order in that case approved 95% of the Company's filed test year position, indicating that these projects were reasonable and prudent. Therefore, the Company is in fact already engaging in early work for these projects, which is directly contrary to the idea they are uncertain.

The Commission should reject Mr. Coppola's proposed bridge period disallowances for so-called "premature" projects, with the possible exception of money not spent on cancelled HVD Strategic Customers New Business projects. The two cancelled projects shown in Exhibit AG-14, page 3, total $27,305,000 for the bridge period. A total of $16,652,000 was spent on those projects prior to cancellation, which means the maximum disallowance for these cancellations should be $10,653,000.

Q. How do you respond to Mr. Coppola's recommendations on so-called "premature" projects in the test year?

A. Mr. Coppola notes that one HVD Strategic Customers New Business project, a dedicated customer substation for $20,619,000, has been cancelled, and he recommends its disallowance. As I will also discuss in my rebuttal to ABATE witness Fitzhenry, this is a reasonable recommendation. Mr. Coppola also calls out the High Probability Projects line item in the HVD Strategic Customers New Business sub-program and recommends its disallowance on the basis that it is a placeholder like in the bridge period. Regarding this recommendation, my response is the same as it was regarding the bridge period, that in this instance the Commission found in Case No. U-21585 that this type of investment was reasonable and prudent, and it should not be disallowed. In discovery request 21870-AG-CE-0480a, the Attorney General asked the Company for specific projects with signed contracts, where two projects were described to have been signed since the case was filed and make up a portion of the High Probability Projects.

Q. Can you discuss the specific so-called "premature" projects in the test year that Mr. Coppola proposes for disallowance?

A. Exhibit AG-14, page 4, lists the Alden, Leslie, and Morrice HVD line rebuild projects. For each of these projects, the Company has indicated that engineering design is already well underway and that construction is on schedule for late 2026 and/or early 2027. Mr. Coppola may want to characterize engineering design as an "early phase of development," but that is not accurate. Engineering design follows project approval and scoping, and is generally completed concurrently with procurement of easements, major equipment, or construction activities. Engineering design is not an early project phase.

Mr. Coppola provides no explanation for why the Company's stated construction schedule is inaccurate; he simply implies that it must be. Since the Company's response shows that construction will take place on these projects during the test year, they are not "premature." It is important to note that the three projects in question are multi-year projects that are not scheduled to be fully complete until later in 2027, which is a common occurrence for HVD line rebuilds.

Exhibit AG-14, page 6, lists the Alma and Blackstone substation rebuild projects. As I have already explained regarding the bridge period, these are multi-year projects that the Commission has already found reasonable and prudent and for which costs are already being incurred.

Exhibit AG-14, page 7, lists the Washington Avenue civil project in Metro Rehabilitation. As the exhibit shows, this project is already well into its engineering design phase now, and Mr. Coppola has given no reason for why the Company would not be able to complete this project during the test year.

Exhibit AG-14, page 8, lists two projects in the HVD Lines and Substations Capacity sub-program. The Company has stated that the Linden 46 kV project design will be complete in the first quarter of 2026, which allows for over a year after design is complete until the end of the test year to complete the proposed investment. For the Wealthy Street Substation project, the Company has stated that design for this will be completed in the first quarter of 2027, well before the end of the test year, and the requested spend in the test year represents design costs and long lead material procurement costs. Mr. Coppola has given no evidence for why the Company's schedule is not accurate.

Exhibit AG-14, page 10, lists two Metro Relocations projects associated with Kalamazoo Avenue. As shown in the exhibit, engineering design is already well underway on these projects, and Mr. Coppola has given no reason for why the Company would not be able to complete these projects during the test year, given that there will be well over one year between the end of design and the end of the test year. It is also worth mentioning that this project is tied to the well-publicized Kalamazoo Avenue two-way street conversion project.[1] With this major street planned for reconstruction, the Company is working with the City of Kalamazoo and its engineering teams to coordinate efforts on Metro system work. There is, quite simply, nothing uncertain about whether this project will happen.

In short, the Commission should reject these proposed test year disallowances, with the exception of the one cancelled project worth $20,619,000.

Q. Does Mr. Coppola have any other recommendations that you wish to address?

A. On pages 64 through 66 of his direct testimony, Mr. Coppola provides further discussion on the HVD Strategic Customers New Business projects that were cancelled. One of his recommendations is that any pre-cancellation costs incurred should not be recovered, which I address in my rebuttal to ABATE witness York. Much of the remainder of Mr. Coppola's concerns seem to stem from the idea that "even after the project is completed and the customer begins operations there is still a high degree of risk that the customer may cease operations or decide to move to another state." While this may be theoretically true, it is not clear that there is actually a high risk of this happening. Projects in this sub-program are typically associated with very large commercial or industrial

[1] Refer to https://www.kalamazoocity.org/Community/Projects/Streets-for-All/Streets-for-All-Kalamazoo-Ave-2026-2027

customers who are themselves making large capital investments in new or expanded factories or other large facilities. Once a business has made a significant investment in a facility and actually commenced operations, the likelihood of suddenly moving to another state is also a low risk indeed.

III. REBUTTAL OF ABATE WITNESS YORK

Q. What is Ms. York's recommendation regarding the HVD Strategic Customers New Business sub-program?

A. On page 30 of her direct testimony, Ms. York notes that the bridge period includes $4,340,000 tied to a project that has been cancelled following the customer's continued postponement of work. She recommends that this amount be disallowed from the bridge period, and that the Company should recover costs from the customer if possible.

Q. Do you agree with this recommendation?

A. No. In this instance, the Company had a signed contract with the customer. In prior rate cases, the Commission has routinely found that having a signed contract with the customer results in the associated investments being reasonable and prudent. Furthermore, this project was presented in Case No. U-21585 and approved by the Commission. It is reasonable, then, that the Company made the investments as its contract with the customer required while it was in force.

As stated in my direct testimony, the Company is seeking recovery from the customer already and will refund any amounts received to customers. In the meantime, it would be unreasonable to prohibit the Company from recovering these costs. If this amount is disallowed, it would create a disincentive for the Company to make needed investment to accommodate new large customers, since there would be an implied risk that

the customer could cancel the deal and leave the Company suddenly facing reasonable and prudent investments that it could not recover on.

Q. What is Ms. York's recommendation regarding Right of Way ("ROW") procurement for HVD projects?

A. On pages 30 and 31 of her direct testimony, Ms. York states that the Company did not provide certain details about its ROW projections, and therefore she recommends that the entire bridge period and test year projected investments be disallowed.

Q. Do you agree with this recommendation?

A. No. Even if Ms. York wanted to argue that some amount of projected ROW procurement was speculative, it would not be reasonable to argue that all of it is and is therefore ripe for disallowance. As shown in Exhibit A-130 (MPK-20), page 2, line 9, the Company has incurred millions of dollars in ROW costs in historical years (note that, through 2023, all HVD ROW costs were assigned to the HVD Lines and Substations Capacity sub-program, which is why they are shown there historically in that exhibit).

But Ms. York is not right to argue that the projected ROW procurement is speculative in the first place. In discovery response 21870-AG-CE-0466, the Company identified HVD Lines Reliability projects for which ROW procurement is needed. Ms. York does not seem to have accounted for this supporting evidence, which is provided as Exhibit A-218 (MLH-6).

IV. REBUTTAL OF ABATE WITNESS FITZHENRY

Q. What is Mr. Fitzhenry's general assessment of the Company's proposed HVD capital expenditures?

A. On pages 24 and 25 of his direct testimony, Mr. Fitzhenry notes that the Liberty Consulting Group ("Liberty") audit in Case No. U-21305 did not find a substantial need for increased

investment in the HVD system, given its relatively low contribution to SAIDI as compared to the LVD system. He provides Table CTF-2 in his testimony as purported further proof of this, noting that none of the outages in Table CTF-2 occur on an HVD voltage, and he notes that "Transmission/Generation outages" accounted for only 0.4% of total customer minutes interrupted. Based on that, he argues that "almost the entirety of outages" on the Company's system from 2022 through 2024 were on the LVD system, meaning there is no need to invest in HVD reliability.

Q. Do you agree with this assessment?

A. No. First, Liberty's audit was published in September 2024, yet on March 21, 2025, the Commission issued its final Order in Case No. U-21585 which authorized a meaningful increase in HVD reliability. In other words, the Commission has supported increased investment in HVD reliability despite Liberty's recommendation. Besides that, specific justifications for each HVD capital sub-program and the spending levels in those sub-programs are provided throughout my direct testimony, with the most succinct summary being found on page 19, line 11, through page 20, line 2.

Mr. Fitzhenry's analysis of the Company's recent outage history also has some issues. Most critically, his Table CTF-2 is based on the Company's response to discovery response 21870-AB-CE-0700, as indicated by his footnote in the table itself. Although this is admittedly not clear in the discovery response, the data provided in the response is LVD-specific data to begin with, which is why there are no outages shown with a fault higher than 24.9 kV. Figures 42, 43, and 45 in Company witness Michael P. Kelly's direct testimony clearly show that outages on HVD lines and on substations are causing SAIDI over the last three years, so it is not accurate to claim that all outages are LVD-related.

Additionally, Mr. Fitzhenry's reference to transmission and generation outages is not relevant to this analysis, because HVD outages are not categorized by the Company as part of transmission or generation outages in the first place.

In short, Mr. Fitzhenry is greatly exaggerating when he suggests that there is no need to invest in HVD reliability.

Q. Does Mr. Fitzhenry propose any disallowances based on his above analysis?

A. Yes. On pages 25 and 26 of his direct testimony, he notes that the HVD Lines Reliability and HVD Substations Reliability sub-programs are intended to improve HVD reliability. Since he has argued that HVD reliability improvements are unnecessary, he proposes to hold investment levels for both sub-programs at 2024 actual levels.

Q. Do you agree with this recommendation?

A. No, except to the extent that I have already conceded some bridge period HVD Substations Reliability dollars in my response to Ms. Durfee. As discussed above, Mr. Fitzhenry's conclusion that there is no need to invest in HVD reliability is severely flawed, and this flawed analysis should not lead to a conclusion that huge amounts of capital investment should be summarily disallowed. My direct testimony provides extensive explanation of the benefits to customers that come from investments in HVD Lines Reliability and HVD Substations Reliability, all of which Mr. Fitzhenry seems to have ignored in favor of a brief appeal to Liberty and a look at LVD outage causes.

Furthermore, as already noted, the Commission already approved an increase in these sub-programs above 2024 actual levels in Case No. U-21585. The Company's bridge period is directly based on amounts approved by the Commission in that Order for the 2025 calendar year and early 2026, with significant work having already taken place.

Mr. Fitzhenry's proposal would disallow money already approved by the Commission when large amounts of work have already been done based on that approval. The Company's test year is based on a continuation of those approved levels of work, and in many instances bridge period projects continue over into the test year, and it would be unreasonable to suddenly disallow that work in such a way that would leave many half-finished projects on the Company's system.

Q. What is Mr. Fitzhenry's recommendation regarding the HVD Strategic Customers New Business sub-program?

A. On pages 26 and 27 of his direct testimony, Mr. Fitzhenry notes that the Company had $20,619,000 tied to a canceled 138 kV dedicated customer substation. He recommends that this amount be removed from the test year. He also states that the Company should recover costs already incurred for this project from the customer; he does not propose a disallowance for this, but it appears to be tied to Ms. York's recommendation about the same project.

Q. Do you agree with this recommendation?

A. I agree that the $20,619,000 for the canceled project should be removed from the test year. As I explained in my response to Ms. York, the Company is seeking to recover bridge period costs related to this project from the customer that it already incurred.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Thank you.

Next is company witness, Michael P. Kelly. Mr. Kelly had direct testimony consisting of a cover page and a 191 pages of questions and answers. He also had rebuttal testimony consisting of a cover page and 60 pages of questions and answers besides his -- his Schedule Exhibit A-12, Mr. Kelly sponsored Exhibits A-112 through A-138, as well as Exhibit A-219, A-220, A-221, and A-222.

THE COURT: Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct and rebuttal testimony of Michael P. Kelly is bound into the record and Exhibits A-112 through A-138, and A-219 through A-222 are admitted.

(At 2:29 p.m. Exhibits A-112 through A-138, and A-219 through A-222 admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

MICHAEL P. KELLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Michael P. Kelly, and my business address is 1945 West Parnall Road, Jackson, Michigan, 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently the Executive Director of Electric Distribution Strategy.

Q. What is your formal educational experience?

A. In 2002, I received a Bachelor of Science in Engineering in Mechanical Engineering from the University of Michigan – Ann Arbor. In 2005, I received a Master of Science in Engineering in Mechanical Engineering from the University of Michigan – Dearborn. In 2009, I received a Master of Business Administration from the University of Michigan – Ann Arbor.

Q. Please describe your business experience.

A. From 2002 to 2007, I was employed by Yazaki North America in Canton, Michigan, as an engineer working in roles that spanned Testing and Validation and Component Engineering. I left Yazaki North America in 2007 to pursue a Master of Business Administration, and upon receiving my degree in 2009, I accepted a position at DTE Energy Company ("DTE") as a Financial Consultant, where I assumed roles in Financial Planning and Analysis, Distribution Operations Decision Support, and Renewable Energy Business Development. In 2012, I accepted a position working in DTE's Electric Strategy organization and was promoted to Manager of the team in 2014. As Manager of the Electric Strategy team, I was responsible for the development of the electric utility's annual

priority plans and long-term financial planning functions. In 2017, I accepted the role of Manager within DTE's Tree Trimming organization. In this role, I was responsible for the long-term and annual maintenance trimming schedules, and execution of contracts with the providers of tree trimming and herbicide services. In October 2018, I accepted a position as a Director, Corporate Strategy at Consumers Energy, where I was responsible for helping to maintain the Company's strategic planning process and working with customers on initiatives such as the Long-Term Industrial Load Retention Rate. In June 2022, I accepted my current role as Executive Director of Electric Distribution Strategy.

Q. What are your responsibilities as Executive Director of Electric Distribution Strategy?

A. My responsibilities as Executive Director of Electric Distribution Strategy include development of the Company's *Electric Distribution Infrastructure Investment Plan* ("EDIIP," also referred to as the "Reliability Roadmap") and implementing the Electric Distribution department's planned activities consistent with its financial plans.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony in the following MPSC cases:

Case No. U-20697	Electric General Rate Case;
Case No. U-20899	Karn 1 and 2 Securitization;
Case No. U-21389	Electric Rate Case;
Case No. U-21585	Electric Rate Case; and
Case No. U-21918	Investment Recovery Mechanism ("IRM").

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide an overview of the Company's electric distribution strategy. I will begin my testimony by detailing how the Company measures electric reliability performance as well as its past actual and projected future reliability performance, based on the impact of the distribution investments proposed in this electric rate case.

Next, I will explain the strategic objectives that guide the Company's investment decisions to achieve reliability performance in the face of the increasingly challenging weather conditions, customer technology adoption, and system deterioration. I will explain the technology projects that support electric distribution as well as the Company's projected electric distribution operating and maintenance ("O&M") spending.

Finally, I will introduce the Company's line loss study; discuss a requirement related to critical inventory as ordered by the Commission in Case No. U-21585; and address certain issues related to advanced metering infrastructure ("AMI").

Q. Are you the only Company witness addressing the Company's electric distribution strategy and investments?

A. No. To provide comprehensive support for the Company's electric distribution requests, six additional witnesses are providing evidence in this proceeding. Company witness Jennifer M. Partlan will support the Company's historical and planned capital investments in the Low Voltage Distribution ("LVD") and Metro systems. Company witness Megan L. Hayward will support the Company's historical and planned capital investments in the High Voltage Distribution ("HVD") system. Company witness Scott A. McPhail will support the Company's historical and planned capital investments in the Grid Automation

Program. Company witness Daniel A. Schmoekel will support the Company's historical and planned capital investments in streetlighting. Company witness Sara E. Stewart will support the Company's historical and planned spending for the Forestry Line Clearing Program. Company witness Andrew R. Snider will support the Company's historical and forecasted spending in Service Restoration.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (MPK-1)	Schedule B-5.7	Electric Distribution Summary of Actual and Projected Capital Expenditures;
Exhibit A-112 (MPK-2)		Electric Distribution Actual and Projected Capital Expenditures Master;
Exhibit A-113 (MPK-3)		Electric Distribution Summary of 5yr Historical Electric Capital Expenditures;
Exhibit A-114 (MPK-4)		New Business Program Summary of Actual and Projected Electric Capital Expenditures;
Exhibit A-115 (MPK-5)		Reliability Program Summary of Actual and Projected Capital Expenditures;
Exhibit A-116 (MPK-6)		Capacity Program Summary of Actual and Projected Capital Expenditures;
Exhibit A-117 (MPK-7)		Demand Failures Program Summary of Actual and Projected Capital Expenditures;
Exhibit A-118 (MPK-8)		Asset Relocation Program Summary of Actual and Projected Capital Expenditures;

Exhibit A-119 (MPK-9)	Electric Other Program Summary of Actual and Projected Capital Expenditures;
Exhibit A-120 (MPK-10)	Wildfire Risk Mitigation Program Summary of Actual and Projected Capital Expenditures;
Exhibit A-121 (MPK-11)	IIJA Grant Funds Summary of Actual and Projected Capital Expenditures;
Exhibit A-122 (MPK-12)	Summary of Actual & Projected Electric & Common O&M Expenses Master;
Exhibit A-123 (MPK-13)	Summary of Actual & Projected Electric & Common O&M Expenses – Operations and Engineering;
Exhibit A-124 (MPK-14)	Summary of 5yr Historical O&M Expenses;
Exhibit A-125 (MPK-15)	Summary of Actual & Projected Electric & Common O&M Expenses – O&M Programs Part 1;
Exhibit A-126 (MPK-16)	Summary of Actual & Projected O&M Programs Part 2;
Exhibit A-127 (MPK-17)	Summary of Actual & Projected O&M Expenses Cost Splits;
Exhibit A-128 (MPK-18)	Summary of O&M Expenses Projected Using Inflation;
Exhibit A-129 (MPK-19)	Amended Reliability Roadmap;
Exhibit A-130 (MPK-20)	2020-2024 Distribution Unit Costs;
Exhibit A-131 (MPK-21)	2023 Electric System Loss Study Report;
Exhibit A-132 (MPK-22)	Mitigating Wildfire Risk in Consumers Energy's Service Territory (2025-2029);

Exhibit A-133 (MPK-23)	Advanced Metering Infrastructure Metrics and Elements;
Exhibit A-134 (MPK-24)	Electric Distribution Summary of Actual & Projected Capital Expenditures per Rate Case Filing Requirements Attachment 11;
Exhibit A-135 (MPK-25)	Reliability Regression Analysis for Environmental Justice Communities;
Exhibit A-136 (MPK-26)	AMI Opt Out Charges;
Exhibit A-137 (MPK-27)	Environmental Justice Hosting Capacity Maps; and
Exhibit A-138 (MPK-28)	Reliability and Disconnections Regression Analysis Overview and Observations.

Q. Please explain the historical, bridge, and test year periods.

A. The historical year is calendar year 2024. The bridge period consists of the 16 months beginning January 1, 2025, and ending on April 30, 2026. The projected test year is the 12 months beginning May 1, 2026, and ending on April 30, 2027.

Q. How is your testimony organized?

A. Below is a Table of Contents that sets forth the subjects of my testimony.

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Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes. I will note that the Regression Analysis at Exhibit A-135 (MPK-25) and the summary at Exhibit A-138 (MPK-28) were prepared by a third-party consultant working with the Company.

I. EXECUTIVE SUMMARY

Q. What is the recent history of the Company's approach to distribution planning?

A. The Company has produced a series of five-year distribution plans known as the EDIIP, the first of which was filed in March 2018, in Case No. U-17990. The most recent iteration of this five-year plan—the third EDIIP—was filed in September 2023, in Case No. U-20147. This most recent iteration is also known as the "Reliability Roadmap," and that

is the term that I will typically use in my direct testimony. An updated version of the Reliability Roadmap is being provided in the instant case as Exhibit A-129 (MPK-19). The first EDIIP dealt largely with the Company's then-existing distribution planning processes, providing visibility for the Commission and other regulatory stakeholders. Since then, the Company's approach to planning has evolved to include new tools and methods of analysis to better anticipate future challenges, with those changes reflected in successive versions of the filings.

The Reliability Roadmap, as amended in this case, defines the Company's current distribution objectives and goals, and the investment plans to meet those objectives and goals, which are reflected in the proposed spending levels in this case.

Q. What are the key objectives for the Company's electric distribution system in the Reliability Roadmap?

A. In the Reliability Roadmap, the Company has established four key objectives for its electric distribution system. These are as follows:

- **Safe** – The Company will continue to design and maintain its distribution system to ensure the safety and security of customers and employees is maintained and ultimately enhanced.

- **Reliable and Resilient** –To ensure system *reliability* during predictable weather variations under normal operating conditions, the Company will improve its capabilities and visibility to proactively operate the system and better manage power quality to provide customers with a grid that remains stable and available. To ensure system *resiliency* and performance, the Company will harden the system where necessary to withstand abnormal conditions driven by increasingly severe and unpredictable weather and climate events.

- **Clean and Equitable** – The Company is building a system that will be modernized, smart, and capable of accommodating changing customer technology adoption patterns, such as electric vehicles ("EVs") and distributed energy resources ("DERs"), for all communities served, ensuring members of disadvantaged communities have equitable opportunities to participate. The

Company will deliver reliability and resiliency equitably across all communities.

- **Competitive** – Provide affordable rates that create value for customers by attracting and retaining businesses that provide jobs and economic opportunities, while ensuring every community—especially our most vulnerable—sees effective energy investment according to its needs, with minimal impact and energy burden.

Q. How will the Company achieve these objectives?

A. I will cover each of these objectives in the section of my direct testimony entitled *Vision for Electric Distribution*. In general, the Company plans to meet these objectives through the multi-year investment plan established in the Reliability Roadmap.

This investment plan incorporates a variety of best practices and forward-looking approaches to achieve reliability through increased line clearing, asset hardening, rehabilitation, and automation.

Critically, the Reliability Roadmap calls for increased investment in many of these high-impact work types, ramping up over the next several years. Beyond the investments in the Reliability Roadmap, the Company is pursuing other activities intended to meet one or more of the objectives, and I will discuss these efforts in the *Vision for Electric Distribution* section of this testimony.

Q. How did the Reliability Roadmap compare to prior strategies presented by the Company?

A. The Reliability Roadmap involved a continuation and an expansion of the Company's long-term distribution strategy of (1) excelling at the basics, and (2) building for the future by reasonably and effectively modernizing the electric grid to deliver safe, reliable, and affordable electricity to customers today, and into the future.

When considering the electric distribution system, "excelling at the basics" consists of investments in and maintenance of core traditional infrastructure, like poles, wires, and substations, all of which improve electric system reliability under normal operating conditions, and resiliency under extreme conditions. The bulk of this work in reliability is concentrated in the Reliability Program and is explained in detail for LVD by Company witness Partlan, and for HVD by Company witness Hayward.

"Building for the future" consists of enabling the transition to cleaner energy resources, including integration of DERs, and increasing automation of the system, using advanced grid technologies to provide the Company's customers with the technology and tools to take greater control over their energy supply, reduce system waste, and optimize DER use. Testimony detailing this work is featured in Company witness Partlan's testimony on Conservation Voltage Reduction ("CVR") and LVD Lines Capacity, as well as Company witness McPhail's testimony on various Grid Automation initiatives.

Q. Please summarize the electric distribution plan in this filing.

A. In this filing, the Company is proposing to invest $1,529,914,000 in distribution system capital projects, and to spend $300,994,000 in distribution system O&M in the test year; as well as $1,598,050,000 in capital projects in the 16-month bridge period. This O&M spending is detailed later in my testimony, and includes programs related to line clearing, as discussed by Company witness Stewart, and to service restoration, as discussed by Company witness Snider.

Line clearing and service restoration both make critical contributions to the Company meeting its electric distribution objectives. The Company's electric distribution system also includes streetlighting, which is addressed by Company witness Schmoekel.

Q. Which exhibits detail the capital for the bridge period and test year and the O&M for the test year?

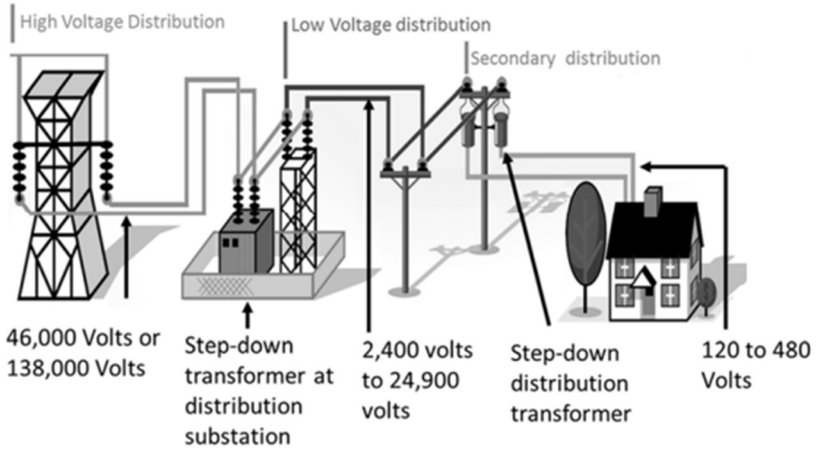
A. Capital spending for both the bridge period and the test year is outlined in Exhibit A-12 (MPK-1), Schedule B-5.7, through Exhibit A-121 (MPK-11). The O&M spending proposed for the test year is detailed in Exhibit A-122 (MPK-12) through Exhibit A-128 (MPK-18).

II. ELECTRIC DISTRIBUTION SYSTEM: OVERVIEW

Q. Please provide an overview of the Company's electric distribution system.

A. The Company's electric distribution system is comprised of the HVD, LVD, and Metro systems. The HVD and LVD systems are shown below in Figure 1.

FIGURE 1
HIGH VOLTAGE AND LOW VOLTAGE DISTRIBUTION SYSTEM OVERVIEW



Q. Please provide an overview of the LVD system.

A. The LVD system is comprised of more than 111,304 total miles of lines, made up of approximately 51,736 miles of primary overhead, 9,885 miles of primary underground, 31,209 miles of secondary overhead, and 18,474 miles of secondary underground.

The LVD system consists of 13 different primary voltages between 2.4 kV and 24.9 kV (grounded-wye and delta). The number of and range of primary voltages differ

because the Company acquired several distribution systems from smaller distribution companies throughout its history.

LVD primary voltage is then further stepped down at the distribution pole-top or padmount transformer to a secondary voltage, serving businesses and residences at voltages between 120 Volts and 480 Volts.

More than 2,000 LVD circuits serve the Company's 1.9 million electric customers, where a circuit is defined as a combination of electrical devices and hardware that are connected and emanate from an LVD substation to deliver electrical energy to customers, operating at a defined nominal voltage.

The LVD system is expansive and subject to the greatest threat from common outage causes like trees, lightning, unexpected load increases, and third-party damage. It is largely a radial system that is not capable of continuing service to customers during outages. Company witness Partlan explains in her direct testimony how the Company is investing in the LVD system to provide reliability and resiliency of electric service to customers. Company witness Partlan also explains in her direct testimony how the Company is investing to convert, where possible, the LVD system from radial operation to looped operation through use of Automatic Transfer Recloser ("ATR") loops.

Q. Please provide an overview of the Metro system.

A. The Metro system provides underground distribution service in the downtown areas of six cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw. Much of the Metro infrastructure was first installed in the 1910s through the 1950s to accommodate electric distribution in already busy downtown areas.

Metro infrastructure is used, both in the past and today, to deal with the density of downtown city centers, facilitate electrical repairs, and for aesthetics.

The primary benefit of the Metro System is to address space limitations where numerous utilities (electric, gas, telecommunications, water, and sewer) must use limited Right-of-Way ("ROW") in public streets and alleys, especially because high-rise buildings have greater utility needs than in lower density areas. The Company's Metro planning group focuses solely on these key downtown areas.

Q. Please provide an overview of the HVD system.

A. The HVD system is composed of two primary areas—lines and substations. Consumers Energy's HVD system consists almost entirely of 46 kV lines (96% of the total HVD miles) and includes radial 138 kV and 69 kV lines (4% and <1% of the total HVD miles, respectively). The HVD system is made up of approximately 180 substations that contain HVD assets, 4,600 miles of HVD lines, and 1,100 LVD substations.

The HVD system is considered the backbone infrastructure of the electric distribution system because it connects the electric transmission system to the Company's LVD system. The HVD system is largely a looped system that is capable of continuing service to customers despite the loss of any single component.

HVD investments are designed to ensure that the HVD system continues to provide a reliable backbone infrastructure critical to supplying the LVD system.

III. VISION FOR ELECTRIC DISTRIBUTION

Q. How is the Company's vision for electric distribution presented?

A. The Company's vision for electric distribution is presented primarily through its Reliability Roadmap, which was historically also known as the EDIIP. The third and most recent Reliability Roadmap was filed with the Commission on September 27, 2023, and is the

Company's articulation of its electric distribution strategy. It is the underpinning document for the distribution plans laid out in this rate case.

Q. How has the Company's vision for electric distribution, as articulated in the Reliability Roadmap, evolved over the last several years?

A. The Commission first directed the Company to file a five-year distribution plan in an Order in Case No. U-17990, primarily to give the Commission visibility into how the Company made distribution investment decisions, and to provide a longer-term outlook into investment plans beyond the single year contained in an electric rate case. In response to this Order, the Company filed its first EDIIP in March 2018.

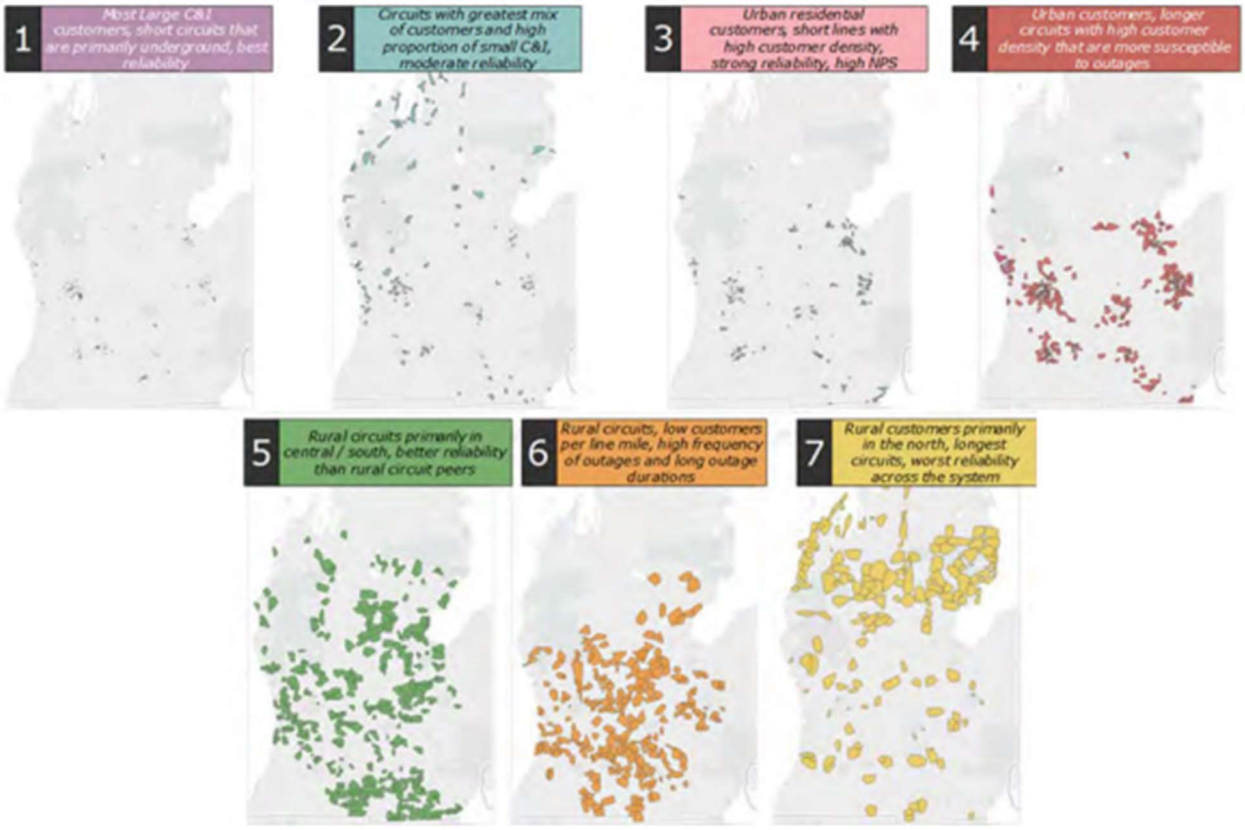
A series of further Orders in Case No. U-20147 in 2018 through 2020 expanded Commission requirements for the Company's second EDIIP, which was filed in June 2021 ("2021 EDIIP"). The 2021 EDIIP introduced the concept of Grid Archetypes.

Q. What are Grid Archetypes?

A. Grid Archetypes were described in extensive detail in the 2021 EDIIP[1] filed in Case No. U-20147. To summarize, the purpose of Grid Archetypes is to consider LVD circuit characteristics beyond reliability metrics to prioritize investments, ensuring that investments are optimally made across the Company's distribution system and across different capital spending programs. This approach ensures that no section of the grid is inadvertently left behind—that both rural and urban customers, and residential, commercial, and industrial customers all benefit equitably from the Company's investments. The seven archetypes, with general geographic locations, are shown in Figure 2 below.

[1] MPSC Case No. U-20147; 2021 EDIIP, pages 51-56.

FIGURE 2
VISUAL REPRESENTATION OF GRID ARCHETYPE LOCATIONS



During planning, the Company allocates capital investment amounts across the archetypes, with each archetype receiving an amount that falls within a range bound by guardrails, as shown in Figure 3 below.

FIGURE 3
LVD ARCHETYPE TARGETED SPENDING RANGES – ILLUSTRATIVE EXAMPLE

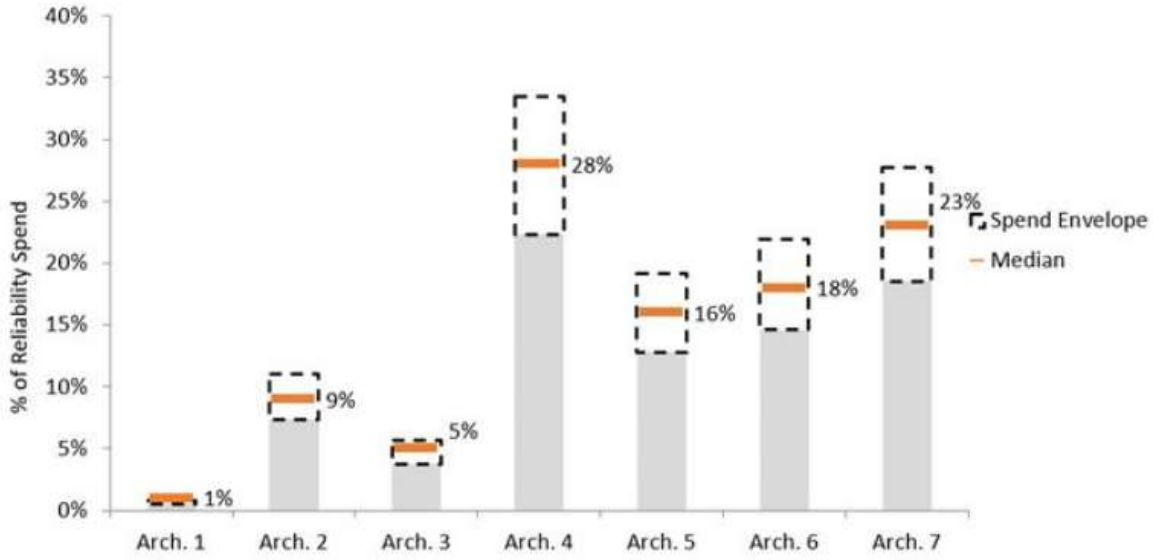


FIGURE 4
LVD ARCHETYPE CHARACTERISTICS

	Arch. 1	Arch. 2	Arch. 3	Arch. 4	Arch. 5	Arch. 6	Arch. 7
% of Line Miles	1%	6%	4%	18%	25%	17%	29%
% of Customers	1%	8%	9%	41%	14%	9%	18%

Q. Are Grid Archetypes updated on a regular basis?

A. Yes. The Company updates its Grid Archetypes periodically, typically every three to four years. The update process involves reviewing and reallocating circuits among the archetypes based on various circuit characteristics and performance metrics, as those characteristics and metrics evolve.

Q. What happened following the 2021 EDIIP related to the Company's distribution strategy?

A. The Company (and other utilities in Michigan) experienced unusually severe storms in August 2021 that caused widespread outages, leading the Commission to initiate a thorough review of reliability in Case No. U-21122.

The Commission concluded that existing distribution investment plans were insufficient to ensure reliability in a world where increasingly severe weather is likely, and in September 2022, the Commission directed the Company to file a new distribution investment plan by September 30, 2023.[2] The Company duly filed its third EDIIP, the Reliability Roadmap, on September 27, 2023, in Case No. U-20147 ("2023 Reliability Roadmap").

In the instant case, the Company has made minor amendments to the 2023 Reliability Roadmap. These amendments primarily concern updating information to reflect another year of actual historical reliability data, and to extend projected investments by another year into the future. Some content has also been revised to reflect issues highlighted by intervenors in Case No. U-21585, or raised by intervenors in other regulatory areas, particularly in the Company's third-party distribution system audit conducted in Case No. U-21305. This amended version of the 2023 Reliability Roadmap is included in the instant case as Exhibit A-129 (MPK-19).

Q. What differentiated the 2023 Reliability Roadmap from the first two EDIIP iterations?

A. In developing the Reliability Roadmap, the Company took to heart the Commission's findings on reliability, as identified in the September 8, 2022 Order in Case No. U-20147, particularly regarding the ability to improve reliability in the face of increasingly severe weather. To address those findings, the Company included more robust analysis of future reliability scenarios in its planning.

[2] MPSC Case No. U-20147, September 8, 2022 Order, page 67: "[C]urrent approaches to distribution planning, the Commission finds, are insufficient to address issues impacting the reliability of utility to service to customers – whether current issues or those forecast for the future. Put bluntly, Michigan's distribution reliability is inadequate, and current plans for improvements are insufficient. Of paramount concern are continuing issues dealing with the safety and reliability of the system, including multiple fatalities within the month of August stemming from contact with downed wires as well as frequent and sustained outages stemming from storm events."

Consequently, the Reliability Roadmap evaluated multiple plausible future scenarios, including a future with increasing severity and frequency of storms, rather than assuming historical weather patterns will continue in the future. The Reliability Roadmap then lays out a multi-year investment plan to address asset deterioration and maintain asset health against identified risks while also hardening assets against increasingly severe weather, so that customer reliability improves even if conditions worsen.

Q. How did the Reliability Roadmap evaluate multiple plausible future scenarios?

A. In developing the Reliability Roadmap, the Company identified the factors that would most likely pose a future risk to the distribution system, with two major factors being identified:

a) increasingly severe weather; and

b) technological innovation driving increased demand on the grid, primarily distributed solar generation, EVs, and electrification of heating.[3]

The Company's analysis indicated the most significant weather-related risks are thunderstorms, other storms (i.e., extreme wind, ice storms), and high heat (which increases demand and increases line losses).[4]

Q. What scenarios did the Company develop for increasingly severe weather and for increased technological innovation?

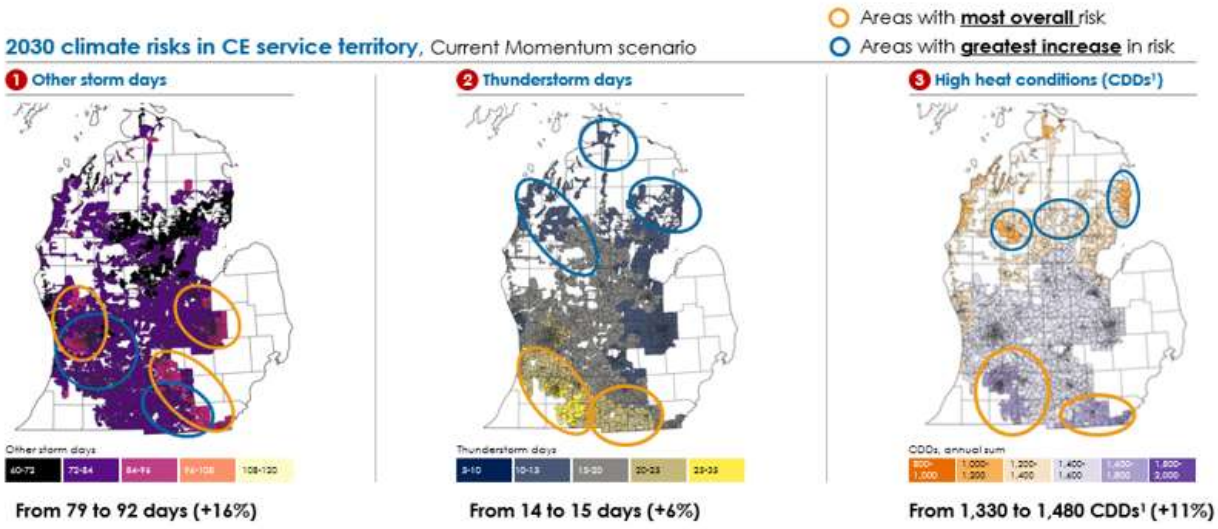
A. The Company developed three scenarios applicable to both major risk categories, called Decelerated Transition ("DT"), Continued Momentum ("CM"), and Accelerated Transition ("AT"), which are described in detail in the Reliability Roadmap.

[3] "Drivers of Change," Reliability Roadmap
[4] "Key Impacts Modeled," Reliability Roadmap

Q. What conclusions can you draw from the Company's scenario modeling?

A. It is critical to note that, in any of the scenarios modeled, climate change will result in more severe weather and extreme heat, in turn creating increasing reliability and resiliency challenges for the distribution system. Regardless of climate policy, the Company's modeling projects an increase of 10-15% in severe weather-related outages by the early 2030s, compared to 2020 levels. The modeling also indicates load constraints due to electrification becoming a larger systemwide concern in the 2030s and 2040s, but this issue will remain localized to a small percentage of circuits for the remainder of this decade. *The most critical issue to focus on is reliability and resiliency in the face of storms, which is a more immediate threat.*[5] The projected impacts are graphically summarized in the Reliability Roadmap as shown in Figure 5 below.

FIGURE 5
2030 CLIMATE RISKS IN CONSUMERS ENERGY SERVICE TERRITORY



This analysis aligns with the Commission's findings that previous distribution investment plans were not commensurate with the challenges posed by extreme weather.

[5] "Impacts of Scenarios on the Distribution System," Reliability Roadmap

Having performed this analysis in developing the 2023 Reliability Roadmap, the Company was better able to identify *where* increased investment is needed, *what kinds* of *investments* are needed, and *what levels of investment* are needed to harden the system and improve reliability for customers even as weather worsens.

As discussed further below in my direct testimony, the Company has, in developing the instant case, also evaluated other investment glidepaths that could affect *what levels of investment* are planned on a year-by-year basis. These other evaluated glidepaths follow recommendations in the Company's third-party distribution system audit conducted in Case No. U-21305. As discussed later in my direct testimony, the Company has also evaluated these different levels of investment and their resulting glidepaths against the Commission's financial incentives and disincentives mechanism targets, established through the Commission's February 27, 2025 Order in Case No. U-21400.

Q. How does the Company intend to address the climate risks identified in the Reliability Roadmap?

A. In the face of these challenges, the Reliability Roadmap outlined the need to increase investment to develop a modern grid capable of mitigating the immediate threats from extreme weather. This was an increase, relative to prior investment levels, in the scale of established investments in infrastructure and spending on line clearing and inspections, while adding new types of resiliency investments.

Q. Can you explain the third-party audit of the Company's distribution system in Case No. U-21305?

A. On October 5, 2022, the Commission issued an Order in Case No. U-21305 that directed the Commission Staff to begin a third-party audit and review of all equipment and

operations of the Company's distribution system and that of DTE. On July 11, 2023, the State of Michigan awarded a contract to perform the audit to Liberty Consulting Group ("Liberty"), following a public request for proposal process. Liberty was directed to file their report in late summer 2024. Over a period of many months, Liberty representatives met with key Company personnel to discuss the Company's distribution practices, and they visited different Company locations to study the state of the Company's distribution system. Liberty filed their report with the Commission on September 23, 2024, also in Case No. U-21305, and presented remarks and responded to questions during the Commission's open meeting on September 26, 2024. At the Commission's direction, the Company filed comments on Liberty's report on November 15, 2024, in Case No. U-21305. After other interested persons filed their own comments on December 16, 2024, in the same docket, the Company filed reply comments on January 17, 2025.

The Company's November 15 comments and January 17 reply comments in Case No. U-21305 present the Company's positions on items raised by Liberty in their report. I will not re-state them in full here, but will discuss how the Company's distribution strategy, as stated in the amended Reliability Roadmap, is incorporating Liberty's insights.

Q. Which of Liberty's recommendations do you wish to address in your direct testimony?

A. In this direct testimony, I will specifically address audit issues with particular importance for (1) the Company's distribution investment strategy, and (2) how distribution reliability is measured. The positions taken in the Company's November 15 comments and January 17 reply comments in Case No. U-21305 remain the same, even if I do not discuss them here.

Q. Which Liberty recommendations do you wish to address related to distribution investment strategy?

A. Liberty recommended the Company place less emphasis on asset age when deciding whether to replace assets. The Company generally agrees with this recommendation. The Company does, in some cases, use age as one of many risk factors in determining whether to replace an asset, but following Liberty's recommendation the Company is no longer pursuing an age-based replacement plan for LVD poles, and will use LVD pole inspections to identify where replacements are needed. Asset-specific approaches for identifying assets for replacement, including how age is weighted, are discussed in more detail by Company witnesses Partlan and Hayward.

Liberty also recommended the Company slow the pace of investment as defined in the 2023 Reliability Roadmap, and evaluate different timeframes for how the Company could meet its reliability goals. The 2023 Reliability Roadmap provided a System Average Interruption Duration Index ("SAIDI") glidepath that would result in second quartile SAIDI performance, excluding Major Event Days ("MEDs"), by 2029, or over approximately five years from when the Reliability Roadmap went into effect[6]. The Company has agreed to supplement the five-year glidepath with seven-year and 10-year glidepaths for comparison, and these will be shown later in my direct testimony.

[6] For purposes of this discussion, the Company is using the Institute of Electrical and Electronics Engineers ("IEEE") quartiles, in which second quartile SAIDI excluding MEDs is better than or equal to 128 minutes based on the five-year historical average (2020-2024 Benchmark Results for 2019-2023 Data). IEEE updates its quartiles each year, meaning the thresholds can change, but this analysis assumes a constant 128 minutes.

Q. What other Liberty recommendations related to distribution investment strategy do you wish to address?

A. Liberty recommended the Company accelerate its forestry line clearing cycle so that the LVD system is on a four- or five-year cycle by 2028. As I will discuss later in my direct testimony, and as Company witness Stewart discusses in her direct testimony in detail, the Company has taken this recommendation into account and is planning to significantly ramp up its line clearing activity to a five-year cycle, although not as rapidly as recommended by Liberty. Increased forestry spending will lead to some adjustments in year-by-year capital investments, but will not eliminate the need for capital investments, as I will discuss later.

Liberty also recommended the Company not pursue its plan to convert open-wire secondary ("OWS") to multiplex, as outlined in the 2023 Reliability Roadmap, given the limited SAIDI benefits. Liberty suggested that "considerations other than reliability enhancement" would warrant OWS conversion. The Company continues to believe that OWS conversion will deliver considerable benefits for public safety, and those benefits will be particularly felt in vulnerable communities in the Company's service territory. Thus, the Company plans to continue with OWS conversions. However, to align with the Commission's final Order in Case No. U-21585, the Company is slowing its investment pace in OWS conversions by approximately one half, and this is reflected in Company witness Partlan's testimony.

Additionally, Liberty recommended the Company delay its plans to convert significant line mileage of overhead conductor to underground, other than the 10-mile pilot approved by the Commission in Case No. U-21389. It is important to note the

Commission declined to authorize any further Overhead-to-Underground conversion ("undergrounding") beyond the pilot in its final Order in Case No. U-21585, because the pilot results had not yet been reviewed, so the Company does not plan to undertake any significant undergrounding work in the bridge period in the instant case. I will discuss the Company's undergrounding plan beyond that, starting in the test year in the instant case, later in my direct testimony, particularly as the Company's pilot demonstrates the cost-effectiveness of undergrounding at scale, and as considerable reliability and resiliency benefits will be produced.

Q. Are there any final Liberty recommendations related to distribution investment strategy that you wish to address?

A. Liberty generally did not find substantial need or benefit to increase investment in HVD lines or in substations, given the fact that most SAIDI minutes, and most projected SAIDI improvements, are related to the LVD system. In her direct testimony, Company witness Hayward discusses why the Company must invest in its HVD system to maintain the reliability and resiliency of the system's backbone, and the Company plans to continue pursuing its investment strategy in this area. The Company is making some adjustments to its plans for HVD lines based on the Attorney General's recommendations and the Commission's Order in Case No. U-21585, finding that certain investment increases should be phased in over multiple years rather than done at once.

Q. What audit issues do you wish to address regarding how distribution reliability performance is tracked and measured?

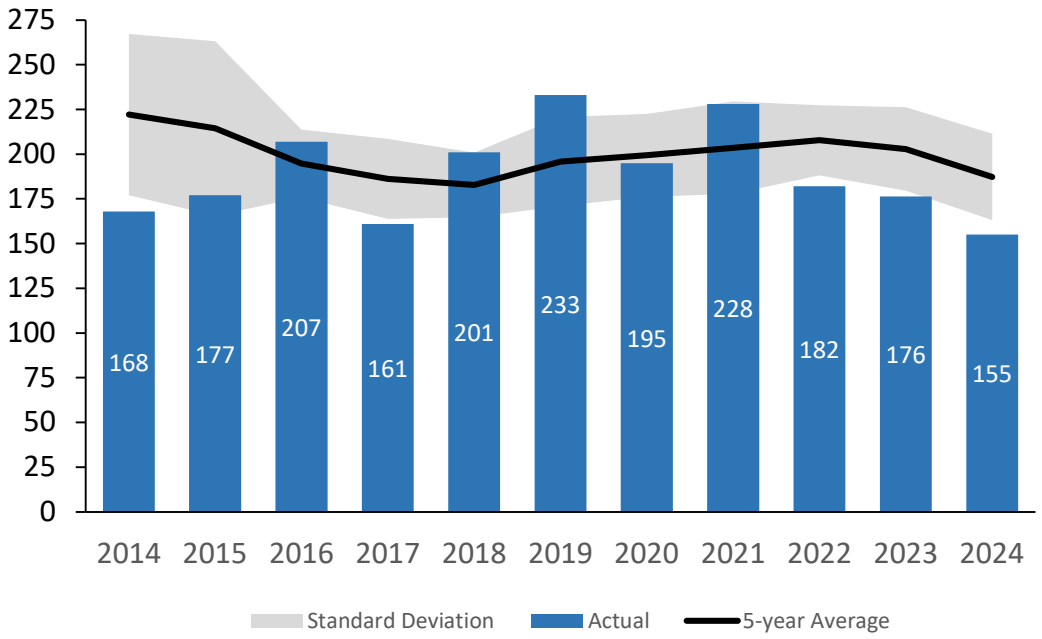
A. Liberty assessed the Company's historical SAIDI performance and concluded the Company has not improved its reliability over the past decade. The Attorney General and

the Michigan Environmental Council/Natural Resources Defense Council/Sierra Club/ Citizens Utility Board of Michigan (collectively "MNSC") provided comments on this point in response. The Attorney General argued that the Company's analysis of historical SAIDI is flawed because the Company focused on SAIDI excluding MEDs, while all-weather SAIDI is more critically important for customers. The Company does track and report all-weather SAIDI, and it is increasingly working to reduce it, particularly through its Resiliency sub-program that was first introduced in Case No. U-21224 in 2022. The Company's IRM, proposed and approved by the Commission in Case No. U-21389, was also explicitly intended to address MED outages. That said, SAIDI excluding MEDs is a well-established industry standard metric, used to focus on reliability on a routine day-to-day basis as the system is designed to handle. The Company is not trying to hide reality or mislead.

Liberty analyzed SAIDI trends in no small part by comparing the Company's reliability in 2014 to its reliability in 2022, noting that 2022 was worse. The Company submits that five-year rolling averages should be used for such comparisons, to limit annual variability and to reduce the arbitrariness of which cut-off dates to use.

When the Company looks at its SAIDI excluding MEDs since 2014, we can see that 2022, 2023, and 2024 were each greater than one standard deviation better than the five-year rolling average, as shown in Figure 6 below. This illustrates that SAIDI excluding MEDs has been consistently better than historical levels for the past three years, which indicates that the Company's reliability investments are delivering results.

FIGURE 6
SAIDI PERFORMANCE COMPARED TO STANDARD DEVIATION (2014-2024)



MNSC also concurred with Liberty in this area, and provided some similar comments to the Attorney General, further arguing the Company's reliability performance has not improved relative to its peers. The Institute of Electrical and Electronics Engineers ("IEEE") updates its SAIDI quartiles each year to indicate where the industry is, which allows for straightforward year-over-year comparisons of how a utility is doing relative to its peers. Using Liberty's 2014-to-2022 comparison for SAIDI and looking at the quartile thresholds for the given years, the Company's position relative to its peers improved for both SAIDI excluding MEDs and all-weather SAIDI, as shown in Figure 7 and Figure 8 below.

FIGURE 7
COMPARISON OF COMPANY SAIDI EXCLUDING MEDS TO PEERS

(minutes of SAIDI)	Single Year Comparison			5-year Rolling Average Comparison	
	2014	**2022**		**2014**	**2022**
Company Performance	168	182		222	208
Crossover point of 3rd to 4th Quartile Performance	159	191		162	179
Better/(Worse) than 3rd/4th Quartile	9 min / 6% Worse	9 min / 5% Better		60 min / 37% Worse	29 min / 16% Worse

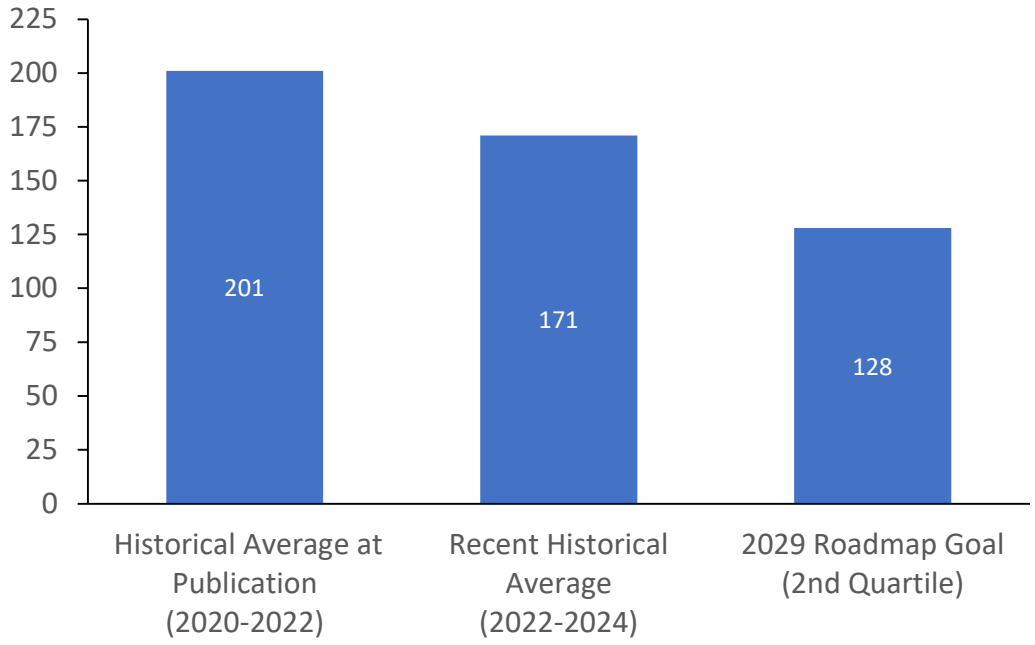
FIGURE 8
COMPARISON OF COMPANY ALL-WEATHER SAIDI TO PEERS

(minutes of SAIDI)	Single Year Comparison			5-year Rolling Average Comparison	
	2014	**2022**		**2014**	**2022**
Company Performance	377	467		625	597
Crossover point of 3rd to 4th Quartile Performance	261	455		451	445
Better/(Worse) than 3rd/4th Quartile	116 min / 44% Worse	12 min / 3% Worse		174 min / 38% Worse	152 min / 34% Worse

Q. What benefits are the investments in the Reliability Roadmap designed to deliver for customers?

A. When the Reliability Roadmap was published in 2023, its investments were projected to deliver SAIDI excluding MEDs in the second quartile or better by 2029, or five years after investments began substantially ramping up. The Company maintains this goal of providing its customers with better than average reliability performance, and the Company has demonstrated clear improvement in delivering reliable service to its customers, having already closed approximately 40% of this gap in performance since the Reliability Roadmap's filing.

FIGURE 9
SAIDI EXCLUDING MEDS PROJECTIONS –RELIABILITY ROADMAP GOAL



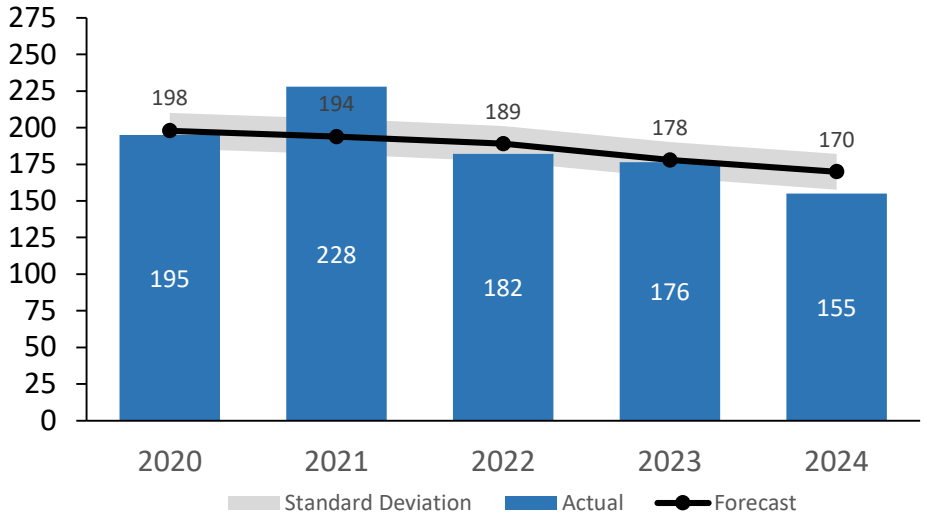
Q. How does the Company project this improvement in reliability performance?

A. The Company's model projects SAIDI, System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") based on historical relationships between these reliability metrics and forestry line clearing spending, capital investment in the distribution system, and certain CAIDI improvements. The model considers future projected forestry line clearing spending, capital investment in key areas, and CAIDI improvements and, in return, the model projects SAIDI, SAIFI, and CAIDI. This model does not incorporate all capital investment, but only those programs, sub-programs, and investment categories that have historically been shown to be most impactful on reliability metrics.

Q. What was the Company's SAIDI performance level in calendar year 2024 and how does this compare to the Company's SAIDI projection from the Reliability Roadmap?

A. The Company's SAIDI performance, excluding MEDs, was 155 minutes in 2024. The projected SAIDI performance for 2024 in the Reliability Roadmap, based on the proposed distribution capital investments, distribution O&M spending, and robust forestry line clearing plan was 170 minutes. While the Company's actual performance in 2024 was better than what was projected in the Reliability Roadmap when it was first filed in 2023, this result was still within 1.25 standard deviations of the projected. As with the variance in 2021, with an actual performance that was nearly 3 standard deviations from the projection, the Company expects actual performance to trend towards the projections, as with the results in 2022 and 2023. Variances are expected in projections, but the Company has confidence in its modeling of the glidepath given a total net variance over the past five years of seven minutes.

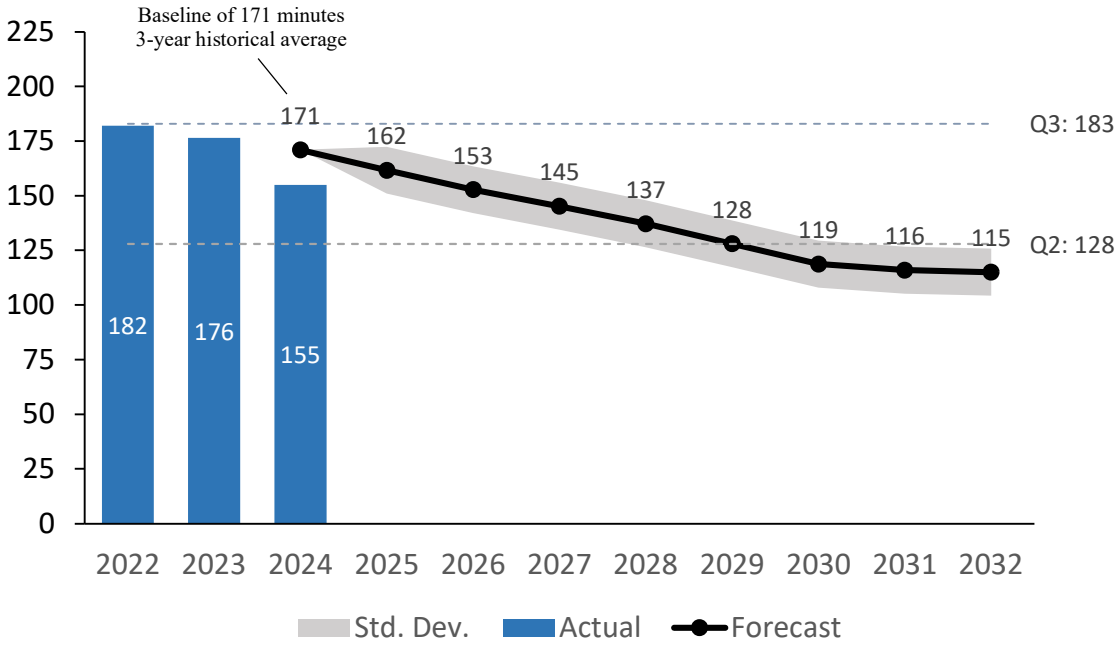
FIGURE 10
HISTORICAL SAIDI PROJECTIONS COMPARED TO ACTUAL



Q. What SAIDI performance level is projected to be produced through the spending outlined in this rate case?

A. The Company's projected glidepath for achieving second quartile reliability, as measured by SAIDI excluding MEDs, remains its primary goal through 2029, and the investments proposed in the instant case will keep the Company on this glidepath. The Company estimates full approval for the spending levels outlined in this case will put the Company on a glidepath to a SAIDI performance of approximately 128 minutes, excluding MEDs, by 2029, a reduction of 43 minutes from the current baseline performance level of 171 minutes. The Company's requested distribution capital investments and distribution O&M spending, as well as the robust line clearing plan discussed by Company witness Stewart, support the planned glidepath to this improved SAIDI performance for customers.

FIGURE 11
SAIDI EXCLUDING MEDS PROJECTIONS



Q. Please provide more detail on the Company's SAIDI glidepath.

A. Using the model described above, the Company's projections for SAIDI, SAIFI, and CAIDI are as shown in Figure 12 below. These figures are net of ongoing deterioration because a certain amount of investment is necessary to keep up with deterioration and to prevent performance from worsening.

FIGURE 12
RELIABILITY PERFORMANCE GLIDEPATH

	Baseline	2025	2026	2027	2028	2029
Net SAIFI	0.93	0.89	0.85	0.82	0.79	0.75
Net CAIDI	184	181	179	177	174	172
Net SAIDI	171	162	153	145	137	128

Q. What Company investments and activities will support this improvement in SAIFI?

A. The Company's model indicates certain investments and activities proposed in this filing will affect SAIFI, as shown in Figure 13 below.

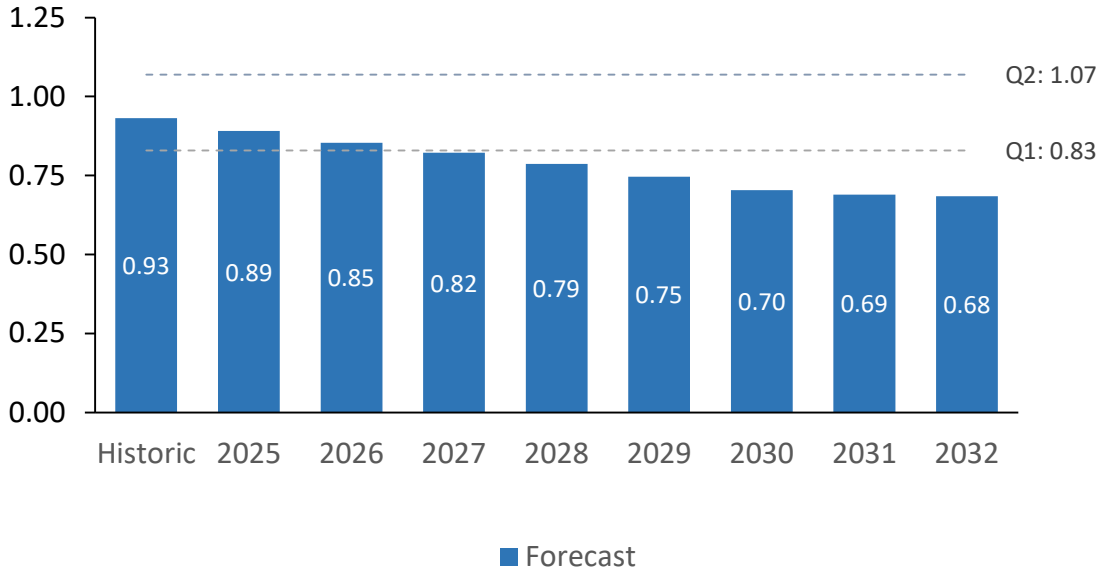
These figures are also net of ongoing deterioration. In some areas, shown as negative numbers, the Company's investments and activities will drive a net reduction in SAIFI over the glidepath period.

In other areas, shown as positive numbers, SAIFI will increase on net due to deterioration; however, the Company's investments in these areas are still necessary to prevent SAIFI from getting even worse. The figures shown for each year are cumulative, not incremental.

FIGURE 13
SAIFI GLIDEPATH IMPACT BY INVESTMENT/ACTIVITY AREA

Investment Category	2025	2026	2027	2028	2029
Line Clearing	(0.003)	(0.008)	(0.018)	(0.035)	(0.063)
Security Assessment Repairs	(0.017)	(0.033)	(0.048)	(0.061)	(0.073)
Zonal Health Projects	(0.024)	(0.042)	(0.050)	(0.057)	(0.063)
Fractionalization	(0.007)	(0.011)	(0.015)	(0.019)	(0.023)
Vulnerable Communities	(0.000)	(0.002)	(0.003)	(0.004)	(0.005)
LVD Pole Replacements	0.001	0.001	0.002	0.002	0.003
ATR Loops	(0.003)	(0.007)	(0.009)	(0.010)	(0.011)
Undergrounding	(0.000)	(0.001)	(0.004)	(0.006)	(0.008)
HVD Pole Replacements	(0.000)	(0.001)	(0.001)	(0.0000)	(0.000)
HVD Pole Top Rehabs	(0.000)	(0.001)	(0.002)	(0.003)	(0.004)
HVD Line Rebuilds	(0.000)	(0.002)	(0.005)	(0.007)	(0.009)

FIGURE 14
SAIFI GLIDEPATH

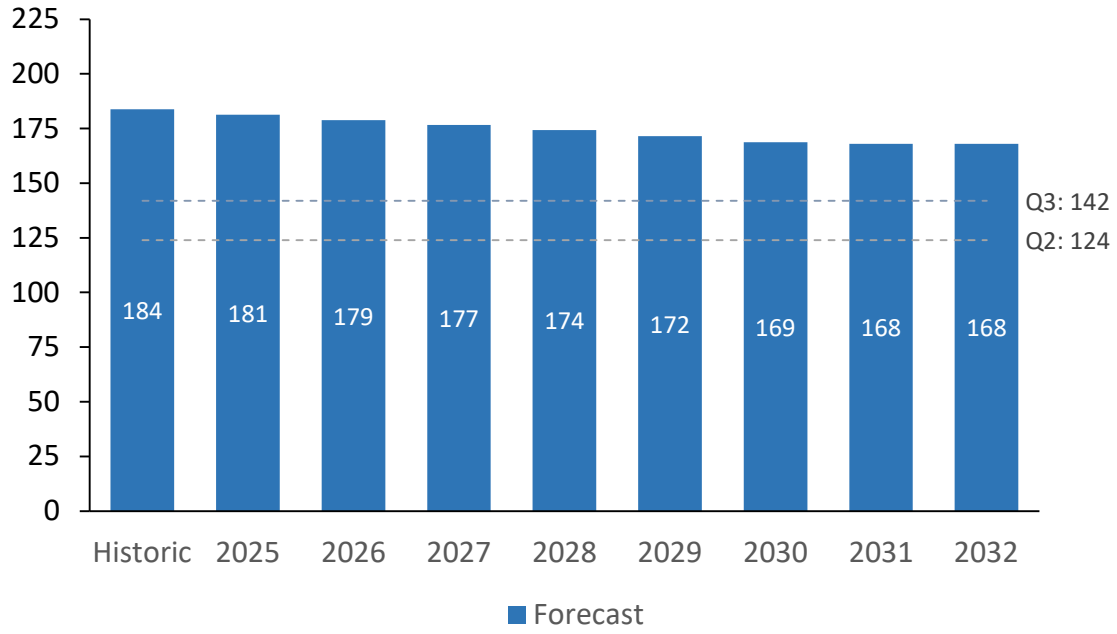


Q. What is the CAIDI glidepath?

A. The Company's model indicates that certain investments and activities proposed in this filing will affect CAIDI, as shown in Figure 15 below.

As the number of outages is reduced, crews will have fewer outages to respond to; this reduction in workload will allow crews to more quickly address outages that do occur. This will produce CAIDI savings.

FIGURE 15
CAIDI GLIDEPATH



Q. What else will the investments identified in the Reliability Roadmap address?

A. Some investments identified in the Reliability Roadmap are also intended to address asset health risk, a concept introduced on page 70 of the Reliability Roadmap.

In these situations, assets may not be experiencing poor reliability today, but the Company has assessed that these assets are in poor health and at heightened risk of failure in the near future. Investing in these assets will make the system more robust.

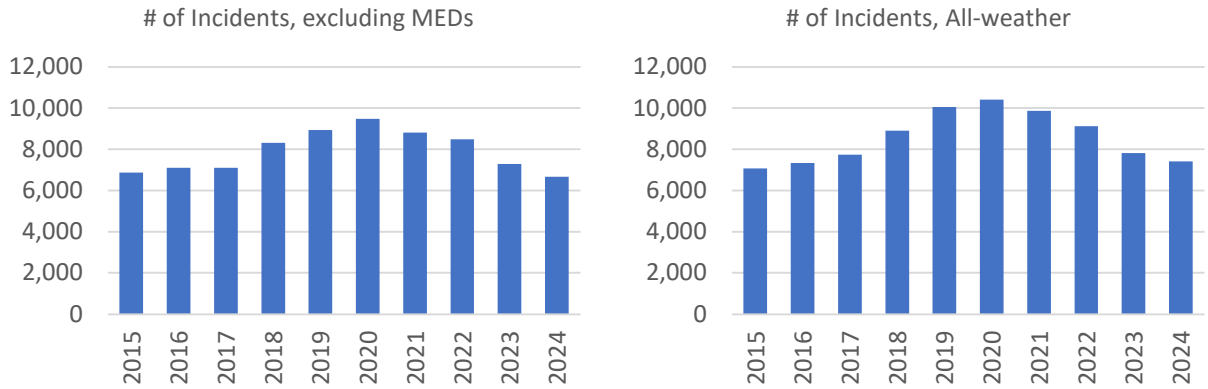
Company witnesses Partlan and Hayward both identify various investments related to asset health risk. Although asset health risk applies to all Company infrastructure to some extent, the issue is most prominent when considering the HVD system, substations, and Metro infrastructure.

Q. If the Company is increasing its line clearing, why are increased capital investments still needed?

A. Although line clearing is an important part of how the Company is working to improve reliability, line clearing alone is not sufficient. For one thing, systemwide line clearing benefits will take time to materialize even as the Company begins shifting to a five-year clearing cycle. In remarks to the Commission on September 26, 2024, Liberty President John Antonuk stated the full benefits of a five-year line clearing cycle would likely materialize across the second iteration of the cycle. A line clearing-only approach, therefore, would delay benefits to customers until the 2030s. To further emphasize this point, the Company has not yet seen a significant systemwide decrease in tree-caused outage incidents due to its increased forestry spending.

Conversely, capital investment in the distribution system has already begun delivering reliability benefits. The Company began earnestly ramping up distribution investments from 2018, when the first EDIIP was filed. Although this increased reliability investment still only touches a small percentage of the system in a given year, the Company began experiencing a clear downward trend in equipment failures starting in 2020, only two years after beginning increased investment, as shown in Figure 16 below. Equipment failure has been a significant contributor to SAIDI in its own right (see Figure 44 later in this testimony). This downward trend indicates that investments have been well-targeted, and that they quickly deliver benefits, and should therefore work in conjunction with increases in forestry work.

FIGURE 16
EQUIPMENT FAILURES, 2015-2024



Even as the Company increases its line clearing activity, trees will still fall on LVD lines and impact the distribution system. Trees are living organisms that are always changing. A tree that poses no threat today may become a hazard before the next clearing cycle (conversely, new assets do not begin to deteriorate to the point of failure for a much longer period of time). This issue is clearly illustrated by the recent experiences of the Lansing Board of Water and Light ("LBWL"). Liberty's report highlighted LBWL's line clearing program since 2014, implemented in response to a catastrophic storm at the end of 2013, and that LBWL has since completed two five-year line clearing cycles of its system. Liberty noted that a July 1, 2024, storm resulted in about 10% of the Company's customers losing power, while a "very low number" of LBWL customers lost power.[7] However, the large storm that impacted Michigan on May 15-16, 2025, illustrated how utilities that follow an aggressive line clearing program can still face negative impacts from storms. This storm left nearly one-third of LBWL customers without power (approximately 32,000 customers), some of them for at least five days, with substantial tree

[7] Liberty September 23, 2024 Report, Case No. U-21305, Part One, Chapter VI, pg. 51.

damage reported.[8] This further illustrates the need for appropriate capital investments to be coupled with line clearing.

The Company's investments in hardening the system will reduce the number of customer interruptions and/or make the interruptions shorter, countering the impacts trees have on the system.

FIGURE 17
HEALTHY, OUTSIDE RIGHT OF WAY TREE IMPACTING DISTRIBUTION SYSTEM[9]



Finally, increased line clearing will eventually reach diminishing returns, or a point at which continued increases will not create benefits in a cost-effective way. While line clearing will be an increasingly important part of the Company's efforts to improve reliability, it is not the only worthwhile approach to improving reliability for customers.

Q. As the Company increases planned line clearing, is it making any adjustments to its capital investment plan?

A. Yes. The Reliability Roadmap, when first filed in 2023, presented a plan to ramp up investments in the equivalent of 280 zonal health projects each year on the LVD system.

[8] "BWL: Full power restoration efforts may take until May 21 after storm rips through region," *Lansing State Journal*, https://www.lansingstatejournal.com/story/news/local/2025/05/16/power-outages-lansing-michigan-consumers-bwl/83666350007/

[9] Photo taken on 8/7/2015 conveying damage to Company's system - substation and circuit were not noted.

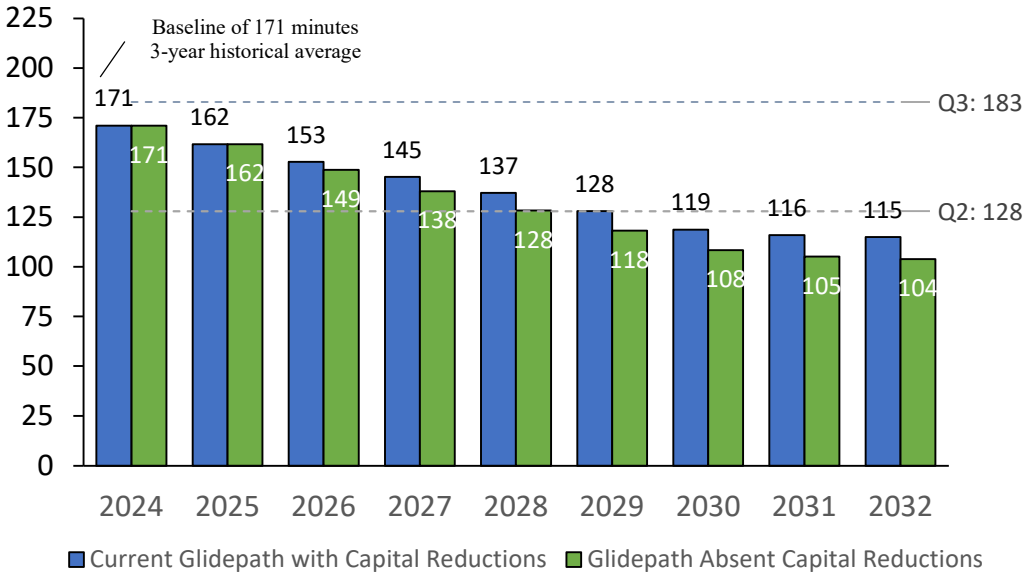
This ramp-up formed a critical component of the Company's projected SAIDI glidepath as it was laid out in the Reliability Roadmap. Since the Company is now proposing a more aggressive line clearing strategy, the SAIDI glidepath modeling discussed above indicates the Company does not need to ramp its zonal health work up as significantly. With the revised line clearing plan, the Company only needs to invest in the equivalent of 85 zonal health projects per year.

This change in the equivalent number of zonal health projects results in an $80 million reduction in the capital that otherwise would have been requested by the Company. In the instant case, this change shows up in the Company's test year plan in the LVD Lines Reliability sub-program, which is discussed in detail by Company witness Partlan.

Q. What would have been the Company's reliability performance had the Company not made changes to its capital investment plan given the increase in line clearing?

A. Had the Company not made the previously mentioned adjustment to the capital plan, the Company would have been able to achieve the Reliability Roadmap goal of second quartile SAIDI a year earlier than originally outlined in 2028 as shown below. The Company maintains that its original timeline to achieve second quartile reliability is reasonable.

FIGURE 18
SAIDI PROJECTIONS WITH INCREASED LINE CLEARING



Q. Has the Company considered alternatives in developing the Reliability Roadmap and the investment plan contained therein?

A. Yes. There are two different ways the Company considered alternatives in the context of distribution planning.

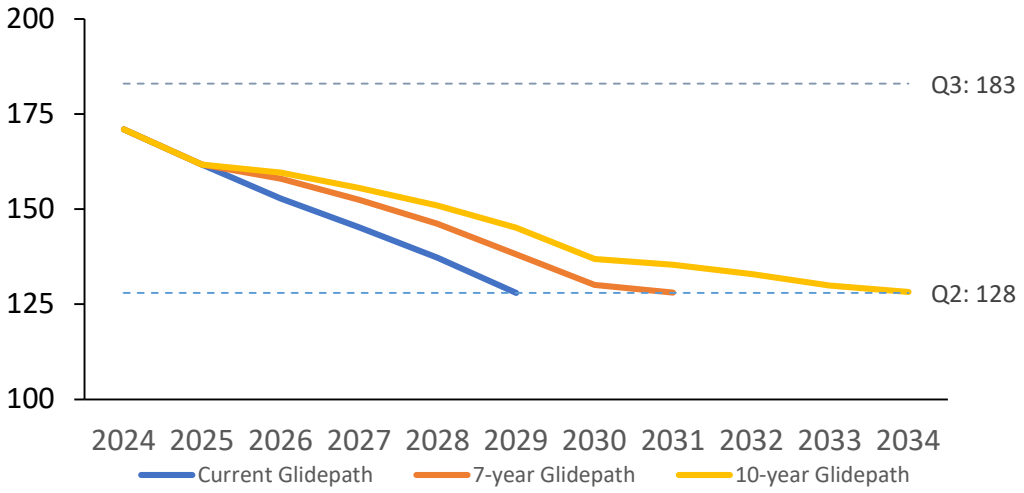
First, we considered alternatives to the Reliability Roadmap as a whole: Are there alternatives to investing in the entire portfolio of assets laid out in the Reliability Roadmap, and at the levels included in the Reliability Roadmap?

Second, we considered alternatives to individual projects: Is the Company prioritizing its investments and choosing the best options to address identified issues on the system? I will address the first of these concerns directly below. I will address the second concern regarding how the Company chooses the right projects, later in my testimony in the Capital Spending Overview section.

Q. What alternatives has the Company considered regarding the overall scope of investment laid out in the Reliability Roadmap?

A. As noted above, the Reliability Roadmap would put the Company on track to providing second quartile SAIDI excluding MEDs by 2029. Based on Liberty's recommendation, the Company has also modeled what it would look like for the Company to slow its pace of investment and reach that SAIDI target over seven or 10 years. The difference between the Reliability Roadmap and these alternative slower glidepaths is illustrated in Figure 19 below.

FIGURE 19
Q2 RELIABILITY GLIDEPATHS



Q. How would these slower glidepaths impact capital investment in the system?

A. These slower glidepaths would nearly eliminate the most beneficial reliability and resiliency programs for the LVD system. The seven-year glidepath would further reduce the number of equivalent zonal health projects to 25 per year, and reduce the investment in ATRs from 30 Loops to 10 Loops per year. The 10-year glide would completely eliminate investment in zonal health projects and ATR Loops. These plans would reduce capital by

approximately an additional $35 million a year for the seven-year glidepath and approximately $50 million a year for the 10-year glidepath.

Q. Are there any other concerns if the Company were to reduce its investments to align with either of these alternative glidepaths?

A. These alternative glidepaths would also result in the Company having a less diverse portfolio of reliability investments.

With the near or full elimination of investments in targeted zones, ATR Loops, and Fractionalization, the Company would be overly reliant on line clearance to achieve its targeted performance.

Q. Why does the Company believe it is important to invest at levels that will deliver second quartile SAIDI by 2029?

A. Pre-Reliability Roadmap investment levels would have led to gradual improvements in SAIDI performance, but even by the end of the decade the Company's SAIDI performance would still be in the middle of the third quartile. Likewise, the slower glidepaths suggested by Liberty would leave the Company's performance lagging in the third quartile until well into the next decade. Customers will benefit from the Company's plan for more rapid improvement in reliability.

Q. Why does the Company believe it is important to deliver better-than-average reliability to customers?

A. First and foremost, the Company is fundamentally committed to delivering reliable electric service to its customers as a core business principle. Other parties have also indicated a need for improved reliability.

For example, the Citizens Utility Board of Michigan ("CUB"), a regular intervenor in the Company's rate cases, including in Case No. U-21585, publishes an annual "Utility Performance Report" that assesses Michigan utilities by a variety of measures, including reliability. In their 2024 edition of the Utility Performance Report, CUB begins its executive summary by stating that "The data in this year's report show Michigan utilities continuing the long-term trend of highly unreliable electric service relative to utilities across the country and those in neighboring states," and "Michigan utilities have continually failed to improve their basic reliability performance, a weakness that is likely to be magnified during severe weather, which experts expect will be more common as the climate continues to warm."[10] CUB's emphasis on poor reliability in their Utility Performance Report is typical of the statements made by these parties about reliability in regulatory proceedings before the Commission; indeed, the first of the two quotes in this paragraph is almost verbatim the same as one from CUB's 2023 report, indicating that this is an ongoing issue, and indicating a consistent demand for significant improvement in reliability.

To cite another example, the Michigan Department of Attorney General has made recent calls for improved reliability and has created a website[11] that seeks to collect power outage data.

[10] Available at https://cubofmichigan.org/wp-content/uploads/2024/12/Dec-2024_5LE_CUB_UTILITYperformanceReport.pdf.
[11] https://www.michigan.gov/ag/initiatives/utilities

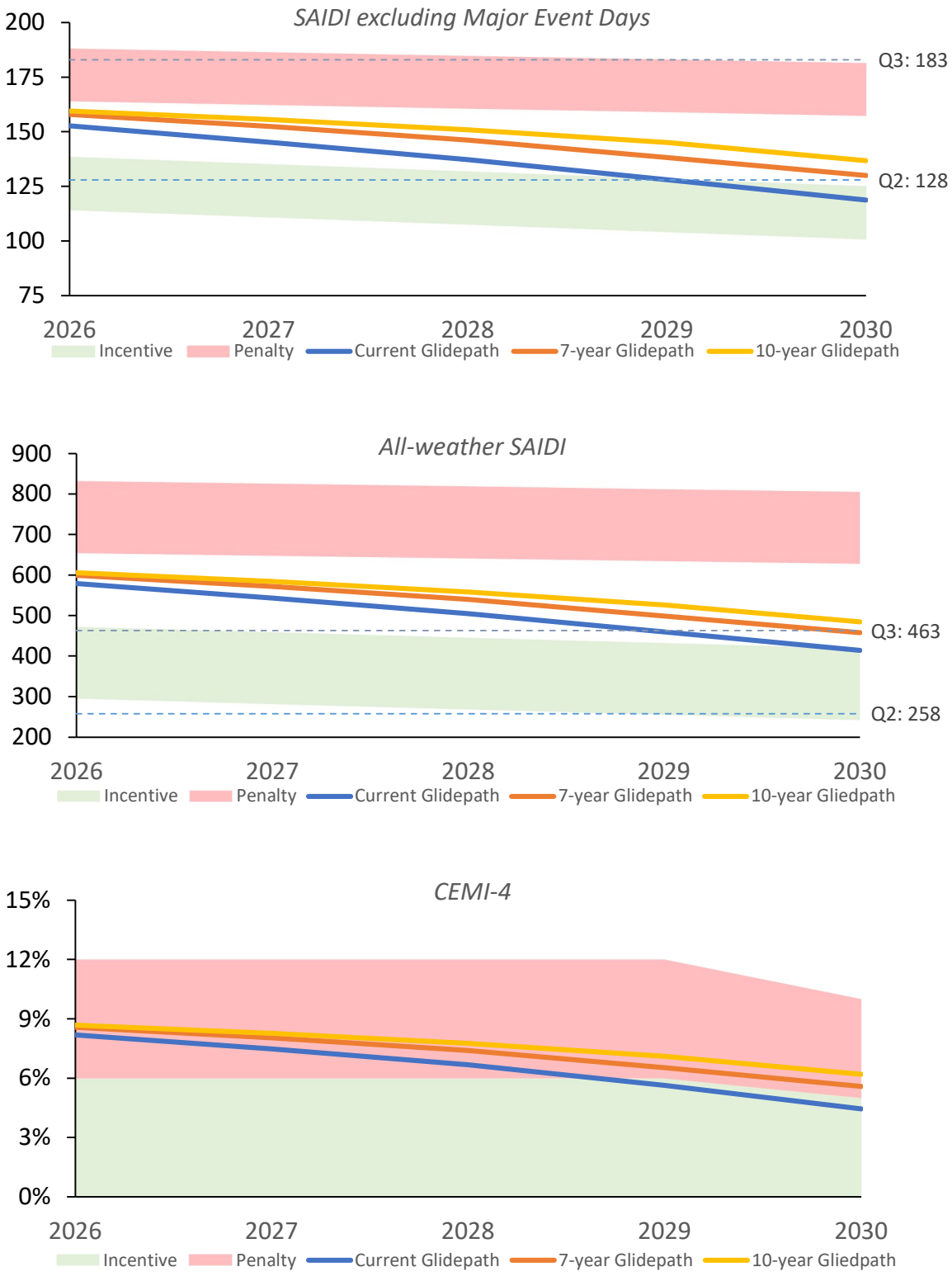
Q. Are there any other external factors leading the Company to conclude that it must invest at the levels defined in the Reliability Roadmap, as opposed to levels reflecting more gradual increases and more gradual improvements?

A. Yes. The Company must consider the reliability performance that it must deliver to meet the targets established through the Commission's financial incentives and disincentives mechanism in Case No. U-21400. This mechanism is commonly referred to as performance-based ratemaking ("PBR").

The Company's PBR targets are being formally set in a separate proceeding in Case No. U-21911, but the provisions set forth by the Commission in its February 27, 2025 Order in Case No. U-21400 define what metrics will be used, and the Order makes clear what performance levels will be used for each metric to determine if incentives are earned or penalties incurred.

In Figure 20 below, the Company has compared its projected performance glidepaths for three of the PBR metrics under the Reliability Roadmap and both of Liberty's more gradual approaches, against the targets based on the February 27 Order.

FIGURE 20
PBR METRICS – GLIDEPATHS COMPARED TO TARGETS



Q. What does Figure 20 demonstrate?

A. Figure 20 illustrates the investment levels set in the Reliability Roadmap put the Company on a glidepath to meeting the Commission's incentive targets by the end of the decade. Conversely, the slower approaches recommended by Liberty do not. For both SAIDI metrics, the Company's performance remains in the deadband where no incentives or penalties apply. For customers experiencing four or more outages per year ("CEMI-4"), the Company's performance would remain in the penalty range. The Company must be allowed to invest at a level that will allow the Company to avoid financial penalties established by the Commission.

In short, both the Commission and various stakeholders expect significantly improved reliability. That significant improvement in reliability can be achieved at the investment levels outlined in the Reliability Roadmap, but not at the reduced investment levels.

Q. Is there a method for calculating a quantitative benefit from the implementation of the Reliability Roadmap?

A. Based on the Interruption Cost Estimate ("ICE") Calculator tool developed by Lawrence Berkeley National Laboratory and Resource Innovations, and funded by the Energy Resilience Division of the U.S. Department of Energy's ("DOE") Office of Electricity, the Reliability Roadmap SAIDI projection will yield up to $6.1 Billion worth of benefits in avoided outage costs.

Q. Has the Company considered other means to achieve similar reliability improvements as those projected in the Reliability Roadmap without the associated increase in capital investment?

A. The Company believes the investments and spending projected in the Reliability Roadmap represent the right mix of work to deliver improved reliability.

In prior years, some parties have asserted that significant increases in capital investment are not necessary to improve reliability, suggesting that because trees are typically a leading cause of outages, the Company only needs to increase its line clearing work to deliver improved reliability. Indeed, this point was raised in the Company's distribution audit, which recommended the Company quickly move to a much more aggressive line clearing cycle. It is important to note that:

a) prior to developing the Reliability Roadmap in 2023, the Company had already significantly increased LVD line clearing from levels seen prior to 2021;

b) the Reliability Roadmap, as filed in 2023, included plans to further increase LVD line clearing;[12] and

c) in 2024, the Company evaluated shorter LVD line clearing cycles in response to the Commission's Order, and results were filed in Case No. U-20697 on September 3, 2024.

Taking into account recommendations from the distribution audit and considering additional data analysis and information that has become available, the Company is proposing a ramp-up to a five-year LVD line clearing cycle, with a plan to be fully on-cycle by the end of the 2030-2031 test period.

As previously discussed, the Company is also proposing more aggressive line clearing through canopy removal on targeted three phase primary sections of circuits.

[12] Reliability Roadmap, p. 86.

Company witness Stewart discusses this line clearing vision and provides detailed justification of it in her direct testimony.

Q. What other alternatives to capital investment exist besides line clearing?

A. Various parties provided comments on the Reliability Roadmap in Case No. U-20147 in February 2024.

Some comments stated the Company might have used the Reliability Roadmap to give more consideration to non-wires alternatives ("NWAs," sometimes also referred to as non-wires solutions, or "NWS"), suggesting that DERs and other approaches could be used to deliver reliability benefits. Similar arguments were made by some intervenors in Case No. U-21585. I will address that suggested approach below.

Additionally, the Company could consider the alternative of simply letting more assets run to failure rather than identifying asset health risks and proactively addressing them. But this would do nothing to improve reliability; when assets fail, customer interruptions are common, so running assets to failure as a matter of choice would lead to worse reliability. Furthermore, reacting to failures is more expensive than proactively addressing issues in a planned way, a phenomenon seen across the industry. For example, the Company's internal crew labor rates are double during storm responses compared to the straight-time rates used for planned work.

Q. Please summarize the Company's views on NWS.

A. NWS may be a viable option to improve distribution reliability, and the Company has studied the potential of NWS in pilots in the last decade, which were discussed in detail in the 2021 EDIIP. At that time, the Company had recently completed two NWS pilots. The results of these pilots from 2017-2018 and 2019-2021 showed that successfully deploying

NWS on the Company's system and generating benefits from those NWS would prove difficult. In short, the Company's findings were that, for even a relatively limited use case such as deferring an LVD substation capacity upgrade:

a) significant lead time was needed to procure the non-wires resources;

b) benefits in one case were unclear; and

c) benefits in another, while theoretically possible, were insufficient when one or two large customers introduced new load.

Using NWS to deliver reliability benefits, as opposed to capacity benefits, requires more certainty about deployment schedule and actual reliability parameters. As far as the Company is aware, no U.S. utility to date has developed an NWS that works as an off-the-shelf solution to improve distribution reliability.

Q. Is the Company considering NWS in any other contexts at this time?

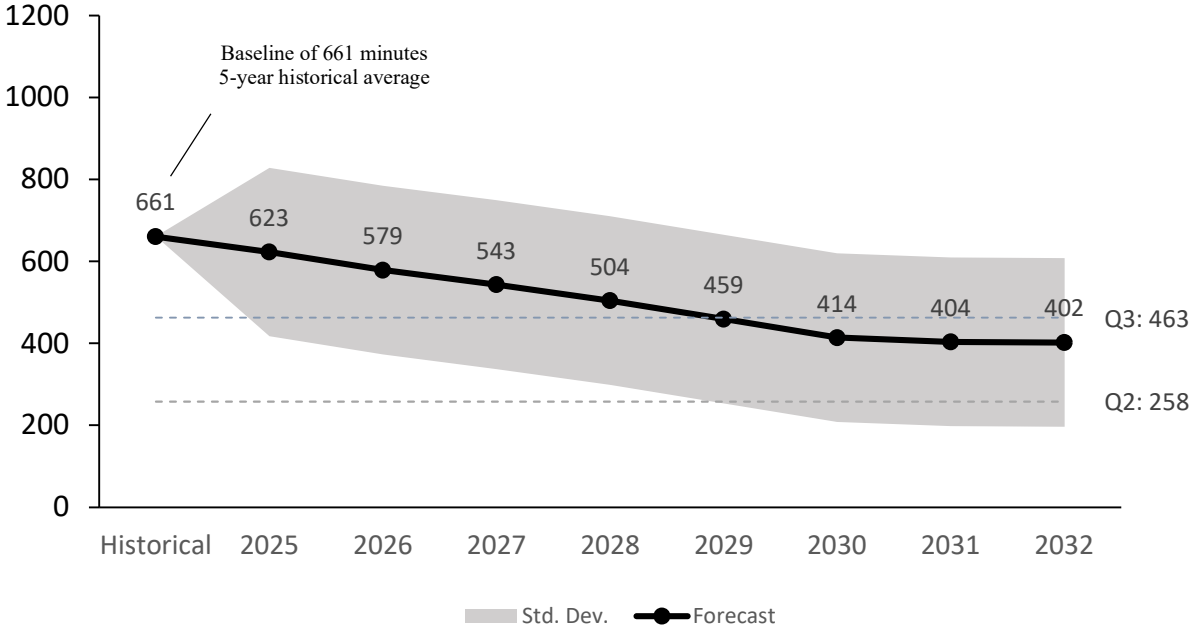
A. In several regulatory proceedings since the 2021 EDIIP was filed, including in Case No. U-21585, some intervenors have urged the Company to continue evaluating NWS. The Company believes its conclusions to date are valid, but it is possible that other approaches besides those used in earlier Company pilots could prove viable. Therefore, in 2025, the Company is working to develop a new NWS pilot. The Company intends to propose this pilot outside of the regular rate case process, using the expedited pilot process the Commission created in its February 23, 2023 Order in Case No. U-20898. According to the terms of the approved process, the Company plans to meet with stakeholders to seek input during 2025, with a goal of filing a proposal as soon as is practicable through the approved process.

Q. Is the Company considering strategies to address reliability metrics other than SAIDI excluding MEDs?

A. Yes. Although the Company gives significant focus to SAIDI excluding MEDs, since it is defined by IEEE and used as an industry-standard metric, the Company understands that other metrics are also relevant. SAIDI including MEDs, or all-weather SAIDI, is important to consider as it reflects the real day-to-day experiences of customers. The Company has already been working to better address all-weather SAIDI, which requires investments to improve resiliency as well as reliability.

In Case No. U-21224, filed in 2022, the Company first introduced its Resiliency investment category as an early step to specifically target all-weather SAIDI. In Case No. U-21389, the Company first proposed an IRM with an explicit goal of supporting investments designed to reduce the occurrence of MEDs (see more discussion later in my direct testimony on the IRM). In the instant case, the Company is proposing a new Vulnerable Communities Resiliency Plan (also discussed later in my direct testimony) with a specific goal of getting communities in economically vulnerable areas into the second quartile of all-weather SAIDI. Furthermore, the Commission has established all-weather SAIDI as a metric for its new PBR framework in Case No. U-21400; as the PBR framework is fully implemented, the Company expects to develop even more investments intended to improve all-weather SAIDI and meet the Commission's expectations.

FIGURE 21
ALL-WEATHER SAIDI PROJECTIONS



Finally, the Company has not met the Commission's Service Quality and Reliability Standards for CEMI-4 in recent years. CEMI-4 has also now been designated as a metric in the PBR framework. To meet the Commission's standards for CEMI-4, and to respond to the Commission's PBR incentives, the Company is increasing its investments in its LVD Repetitive Outages sub-program, as discussed by Company witness Partlan, to specifically target this metric.

Q. How is this rate case tied to the Company's Reliability Roadmap?

A. In short, the overall distribution plan outlined in this electric rate case corresponds with what was presented in the Reliability Roadmap in terms of investments and work activities that will take place during the bridge period and test year; as noted above, the version of the Reliability Roadmap included in the instant case as Exhibit A-129 (MPK-19) includes some amendments that differ from what was filed in September 2023.

While the Reliability Roadmap lays out a distribution strategy and investment plan over multiple years, this rate case translates particular years of that investment plan into specific investment programs, sub-programs, investment categories, and projects.

Q. Can all of the distribution investment included in this electric rate case be found in the Reliability Roadmap?

A. No. The Reliability Roadmap focused on strategic investments needed to improve reliability and resiliency and/or address asset health risk. Investment not related to these objectives, particularly in the New Business, Asset Relocations, and Demand Failures programs were not discussed in significant detail in the Reliability Roadmap.

Q. Does the Reliability Roadmap establish any other fundamental building blocks of distribution strategy?

A. The Reliability Roadmap also states the four distribution objectives that I defined in the Executive Summary of this direct testimony: Safe, Reliable and Resilient, Clean and Equitable, and Competitive. Taken altogether, these provide the Company with a comprehensive distribution strategy. I will explain specific activities designed to meet these objectives later in this direct testimony.

Q. Are there any other factors that affect the Company's electric distribution strategy?

A. Yes. While the Company is building for the future of the electric distribution grid, it is simultaneously supporting the Company's Clean Energy Plan, which has been defined most recently in the Company's 2021 Integrated Resource Plan ("IRP").

Q. Please explain how the Clean Energy Plan informs the Company's distribution strategy.

A. The IRP relied on the use of CVR, discussed in greater detail in the direct testimony of Company witness Partlan, to reduce generation needs as a means of addressing the Company's electric capacity requirements. The CVR investments discussed by Company witness Partlan represent a continuation of this component of the Clean Energy Plan.

Objective: Ensure safety and security

Q. How do the Company's proposals in this case support the Company's objective to ensure safety and security to workers and the public?

A. Improving overall safety and security for customers and employees remains the top priority. The Company designs its distribution system to ensure safety is enhanced through rehabilitation and preventative maintenance of assets as well as using automation technology to spot issues before they occur. In particular, capital spending in the Rehabilitation sub-programs proactively replaces assets judged to be at risk of imminent failure by Company personnel. This vital work not only enhances the reliability of the system by addressing system deterioration, but also protects the public from assets at a higher probability of failure.

Q. Do any of the investments identified in the Reliability Roadmap primarily support safety goals?

A. Yes. The Reliability Roadmap identified voltage conversions, subsurface transformer replacements, open-wire secondary conversions, and key investments to improve public safety. Additionally, the Company's new effort to perform groundline inspections of LVD

poles and replace any pole in poor asset health will improve both public and employee safety. Company witness Partlan discusses these investments in her direct testimony.

Q. Is the Company performing any other work that will enhance public and employee safety?

A. Yes. The Company plans to continue the O&M spending associated with its Wildfire Risk Mitigation Program, first introduced in Case No. U-21585. The Company also proposed capital investments for Wildfire Risk Mitigation in Case No. U-21585, but these were opposed by some parties and the Commission did not approve the capital part of the proposal. Per the Commission's directions in their final Order in Case No. U-21585, the Company is pausing the capital investments associated with Wildfire Risk Mitigation while it reassesses the costs and benefits of the program utilizing data specific to its distribution system.

Q. What is the Company's Wildfire Risk Mitigation Program?

A. In the 2023 Reliability Roadmap, the Company analyzed multiple potentially emergent risks, such as wildfires and extreme precipitation, in its modeling.

As shown in Figure 22 below, these risks were originally deemed less immediate to Company assets compared to thunderstorms, high heat, and wind. However, multiple recent major wildfires in the United States, including wildfires triggered or exacerbated by utility infrastructure, illustrate the threat posed by wildfires. As a result, the Company has developed a program to mitigate wildfire risk. This plan is detailed in the Company's report *Mitigating Wildfire Risk in Consumers Energy's Service Territory*, which is included as Exhibit A-132 (MPK-22). In developing its plan, the Company researched other utilities' publicly available wildfire risk mitigation plans and held benchmarking

discussions with several utilities, and concluded that there are four types of wildfire risk mitigation activities in use in the industry:

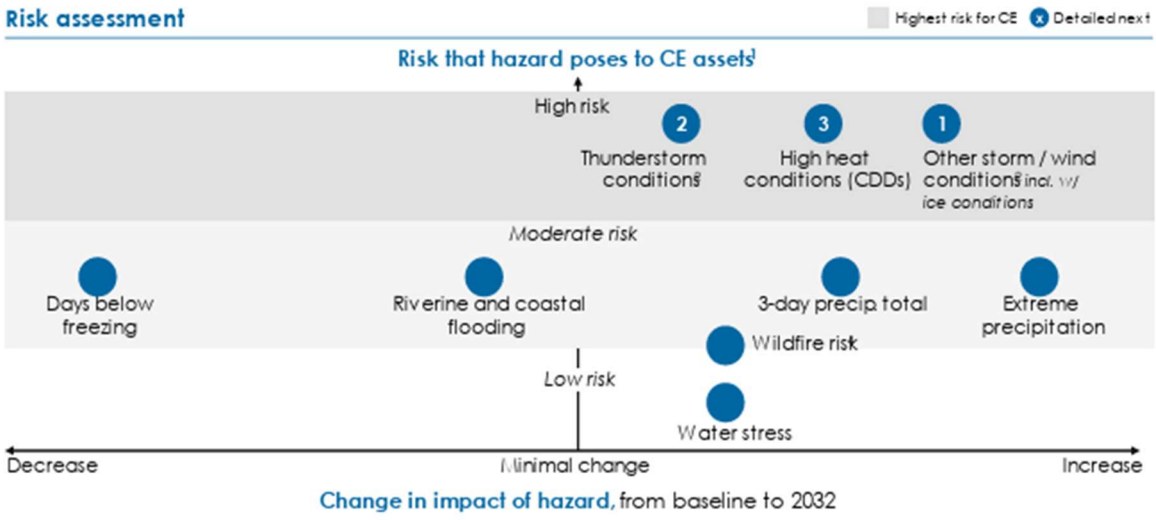
- **Situational Awareness:** Technology-based approaches that produce large amounts of data to inform decisions, including wildfire weather forecasting, enhanced inspections, sophisticated wildfire risk modeling, fire detection cameras, and fire spread modeling.

- **Operational Procedures:** Operating procedures designed to reduce ignition risk in wildfire-prone weather conditions, including modified field operating procedures, modified recloser settings, public safety power shutoff, and wildfire-specific emergency preparedness.

- **System Hardening:** Traditional investment in the system, including sectionalizing devices, installing covered conductor, undergrounding, and building microgrids.

- **Vegetation Management**: Increased frequency of line clearing, with expansion of scope to remove canopy on targeted three phase primary lines.

FIGURE 22
RELIABILITY ROADMAP CLIMATE RISKS EVALUATED



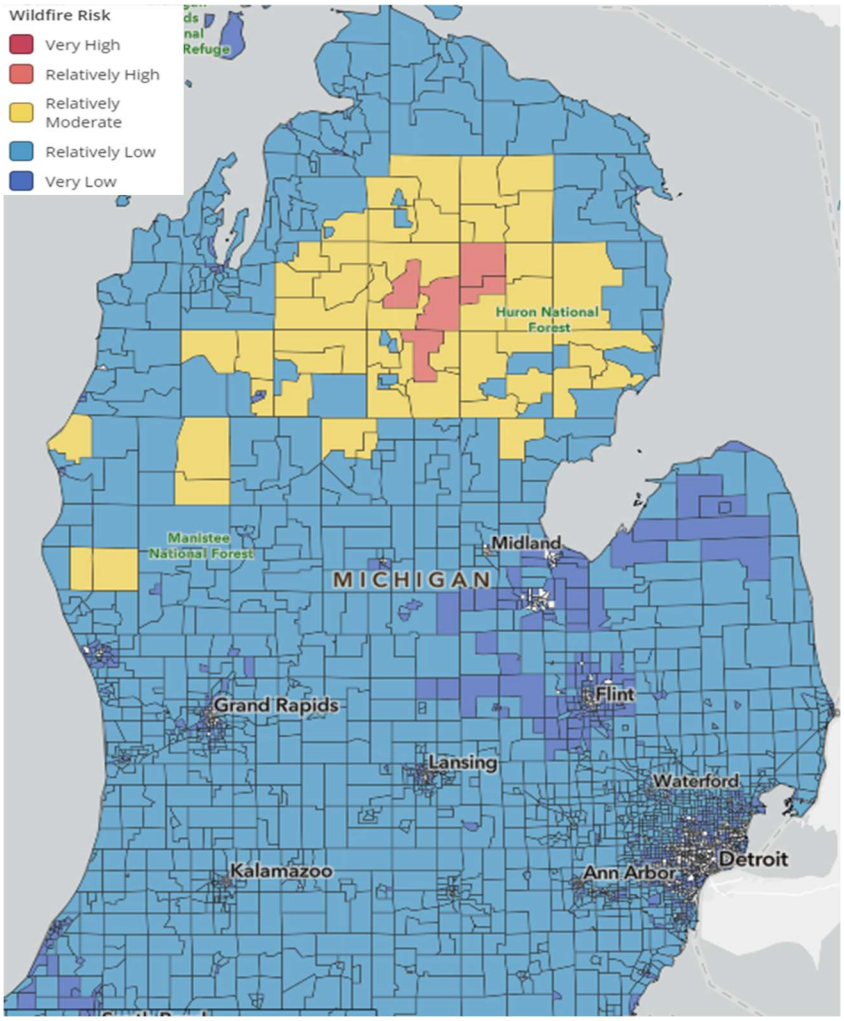
Q. What parts of the Company's system are at the highest risk from wildfires?

A. The Federal Emergency Management Agency ("FEMA") produces a *National Risk Index* map of the United States that includes a Wildfire Risk Index score and rating for communities, indicating their relative risk for wildfires compared to the rest of the country.

According to FEMA, approximately 21% of the Company's service territory is located in areas with elevated wildfire risk, primarily in the north central Lower Peninsula. This is represented in Figure 23 below.

FIGURE 23

ELEVATED WILDFIRE RISK AREA IN MICHIGAN'S LOWER PENINSULA[13]



[13] FEMA National Risk Index (https://hazards.fema.gov/nri/map)

Q. How does this risk level in Michigan, as defined by FEMA, compare to the risk levels in other parts of the U.S. that have had severe utility-related wildfires?

A. FEMA identifies Hawaii and Texas, two other states with major wildfires in recent years, as having a small number of census tracts with a "Very High" risk whereas census tracts in Michigan have a maximum rating of "Relatively High."

That said, it is important to note the area surrounding Lahaina, Hawaii, on the island of Maui, has a "Relatively High" rating by FEMA. This area experienced a devastating utility-related wildfire on August 8, 2023, in which 100 lives were lost, 2,200 structures were destroyed, and $5.5 billion worth of property was damaged[14].

While other states may have different climates from Michigan's, the FEMA wildfire risk ratings are comparable between Michigan and the area surrounding Lahaina, Hawaii. Consumers Energy's proposed wildfire program is a reasonable attempt to mitigate wildfire risk in its service territory.

Q. What work does the Company include in the Wildfire Risk Mitigation Program?

A. Wildfire Risk Mitigation activities, and the corresponding work for 2025 through 2029, are described in the Company's wildfire risk mitigation report in Exhibit A-132 (MPK-22). However, the work proposed in the instant case represents only a continuation of the work approved in Case No. U-21585, including activities related to addressing situational awareness, operational procedures, and vegetation management. System hardening capital investments are not included in the instant case.

The Company intends to provide additional support for the capital needed to mitigate the risk of wildfires in the communities in Northern Michigan in a future case.

[14] https://www.usfa.fema.gov/blog/preliminary-after-action-report-2023-maui-wildfire/

As shown in Exhibit A-124 (MPK-14), line 53, the Company is projecting $512,000 in O&M in the test year in this case. This total amount is broken down as follows:

- $12,000 for wildfire-specific weather forecasting; and
- $500,000 for Light Detection and Ranging ("LiDAR").

Q. What are the Company's plans for wildfire risk mitigation beyond the test year in the instant case?

A. The five-year plan presented in Exhibit A-132 (MPK-22) is the Company's effort to be fully transparent about future workplans and cost, as well as to follow industry best practices for publishing multi-year wildfire risk mitigation plans. However, the Company will continue to learn more about wildfire risk in Michigan, new wildfire risk reduction strategies and technologies, and how changing weather patterns impact the region. As it does so, it will continuously improve this plan by leveraging industry experts and peers, and learning about and deploying best practices.

The Company is including an updated five-year plan in Exhibit A-132 (MPK-22) to show the current vision for its Wildfire Risk Mitigation Plan given the Commission order that only approved funding for O&M in Case No. U-21585.

Absent capital investment and the associated benefits of System Hardening, the Company will leverage the three remaining best practices of Situational Awareness, Operational Procedures, and Vegetation Management.

It is through these remaining activities that the Company will mitigate wildfire risks in its Northern Michigan communities.

Objective: Ensure system Reliability and Resiliency

Q. How do the Company's proposals in this case support the Company's objective to improve reliability and resiliency?

A. The Company continues to invest hundreds of millions of dollars in the distribution system to ensure its reliability and resiliency, repairing and replacing distribution assets, performing line clearing work, and investing in technology and automation projects to modernize the grid.

As already discussed above, the Reliability Roadmap, with its investments to reduce SAIDI and reduce asset health risk, is driving a large increase in investment in reliability and resiliency. In total, the Company is directing $697,127,000 of test year capital toward the Reliability Program.

LVD Reliability sub-programs are detailed in Company witness Partlan's testimony. Company witness Partlan also addresses the LVD Lines Capacity sub-program that also has clear reliability implications in the Reliability Roadmap. HVD Reliability sub-programs are detailed in Company witness Hayward's testimony. Grid Automation investments are detailed in Company witness McPhail's testimony. Additionally, the O&M dollars spent on line clearing improves reliability by mitigating the risk posed by trees adjacent to distribution assets.

To further support the Company's efforts to invest in reliability and resiliency, the Company is proposing an updated IRM covering certain capital investments, following the IRM approved in Case No. U-21389. The updated IRM is discussed by Company witness Heidi J. Myers, and additional details are included later in my direct testimony.

Q. What external sources has the Company consulted for industry best practices for improving reliability and resiliency?

A. The Company has consulted, among other things, the Electric Power Research Institute's ("EPRI") *Distribution Grid Resiliency* reports published in 2015.

EPRI published a report on the prioritization of options for grid resiliency[15] incorporating research that EPRI conducted on overhead structures, vegetation management, undergrounding, grid technology, and storm response practices. This report provided a benchmarking analysis of the costs and benefits of various options for improving reliability and resiliency the Company can apply to its distribution planning, as well as discussion on how to rank the reliability of circuits so that projects can be prioritized.

While that EPRI report provides a foundation for the Company's distribution investment prioritization, the Company continues to stay active in various EPRI working groups, each of which allow Company personnel to stay up to date with best practices and potential breakthroughs at other utilities or from others doing research. Within the electric distribution space, these working groups include subject matter such as line design, substation operation and maintenance, distribution cybersecurity, and integration of DERs.

Q. Which Company proposals in this case specifically support the resiliency of the system against increasingly severe weather?

A. The Resiliency sub-program found in Company witness Partlan's testimony includes two key efforts to support the resiliency of the system: Fractionalization and undergrounding.

[15] *Distribution Grid Resiliency: Prioritization of Options.* EPRI, Palo Alto, CA: 2015. 3002006668.

Fractionalization is the practice of segmenting LVD circuits into smaller sections with fewer customers to reduce the impact of outages. *Undergrounding* completely replaces certain sections of overhead LVD lines with underground lines and associated equipment protecting distribution lines from weather and trees.

Q. How has the Company been treating undergrounding in rate cases?

A. In Case No. U-21389, the Company proposed an undergrounding pilot to allow the Company to explore how undergrounding can help improve reliability for customers, comparing the benefits and costs of this work. The Commission approved this proposal to cover approximately 10 miles of undergrounding, and the Company executed on this work in 2024 and early 2025. In Case No. U-21585, the Company proposed to expand on the pilot work with an additional 25 miles of undergrounding as part of a multi-year initiative to perform more undergrounding work as discussed in the Reliability Roadmap. That expansion in Case No. U-21585 included mileage specifically dedicated to addressing environmental justice ("EJ") communities, and to addressing wildfire risk mitigation. Ultimately, the expansion of the undergrounding conversion program was not approved in Case No. U-21585 because the results of the pilot from Case No. U-21389 were not yet available.

Q. What have been the results, to date, of the pilot approved in Case No. U-21389?

A. In Case No. U-21389, the Company included a list of circuits to be included in the pilot. The Company was not able to convert some of these circuits to underground during the test year due to an inability to secure easements. However, the Company was able to identify substitute circuits for each of these cases using the same selection criteria the Company defined when establishing the pilot in Case No. U-21389.

Following these adjustments, the Company has fully field-completed undergrounding on 8.8 miles of lines, with the remaining miles that were approved in the pilot set to be complete in spring 2025. The pilot was particularly concerned with validating the costs of undergrounding. Ultimately the 8.8 miles converted in the test year of Case No. U-21389 had an average actual cost of approximately $422,000 per line mile of underground installed.

Q. How do these costs per line mile compare to the Company's projections in Case No. U-21389?

A. In Case No. U-21389, the Company projected that underground conversions would cost $400,000 per line mile, so the actual costs discussed above were, on average, higher. However, much of the discrepancy is due to a single outlier project included in the pilot. The Company converted 0.6 miles of the Saugatuck-Douglas circuit at a cost of $902,000 per line mile. This project ended up costing much more than the others because it required full boring (as opposed to less expensive trenching or plowing) and it was in a narrow ROW with high customer density on a busy road requiring traffic control. If this outlier is discounted, the average cost for the pilot was approximately $398,000 per line mile of underground installed.

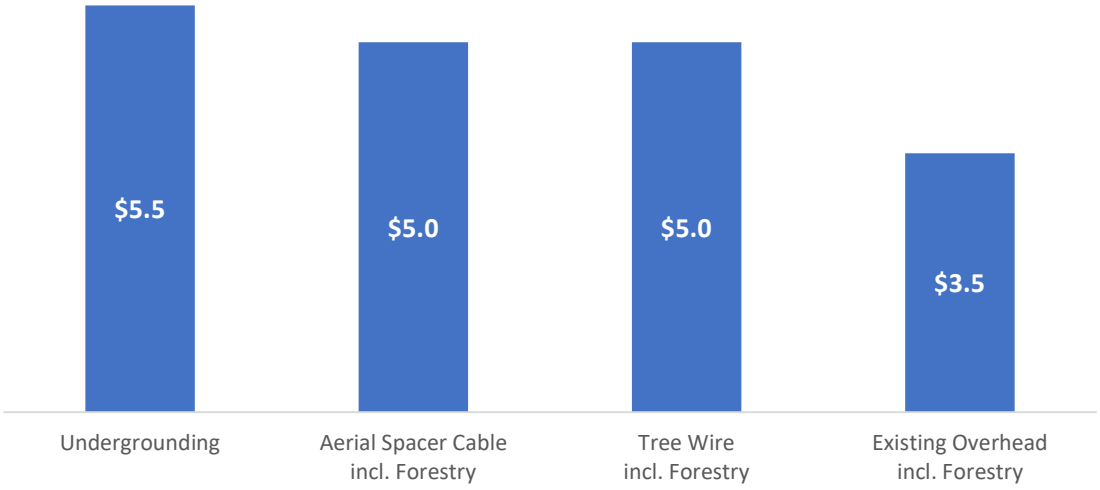
In considering these averages, it is important to note that the Company also had projects in the pilot that came in cheaper. For example, the Company undergrounded 1.4 miles of the Conklin Park-Holly circuit in Newaygo for $145,000 per line mile. This circuit was cheaper because it could be done entirely with plowing (as opposed to boring) and was in a low-density rural area with easy ROW access and away from busy roads.

Plowing is a technique for installing underground lines that involves a minimal amount of disruption on the surface, and it is therefore less expensive than boring.

Q. Based on the pilot results, how do the costs of undergrounding compare to alternatives?

A. The Company has compared undergrounding costs to those of hardening alternatives such as installing Aerial Spacing Cable and Tree Wire, and of simply maintaining traditional vegetation management. In Figure 24 below, the Company has compared the Present Value of the Revenue Requirement ("PVRR") for its undergrounding pilot projects to the PVRR of installing Aerial Spacer Cable or Tree Wire for single-phase LVD. This figure is based on using the utility cost test ("UCT"), which is a cost-benefit analysis framework used to measure the costs and benefits incurred by the Company.

FIGURE 24
PILOT PROJECTS PVRR OF UNDERGROUNDING AND ALTERNATIVES - $ MILLIONS



Q. How do the pilot costs of undergrounding compare to alternatives if viewed through a societal cost test ("SCT")?

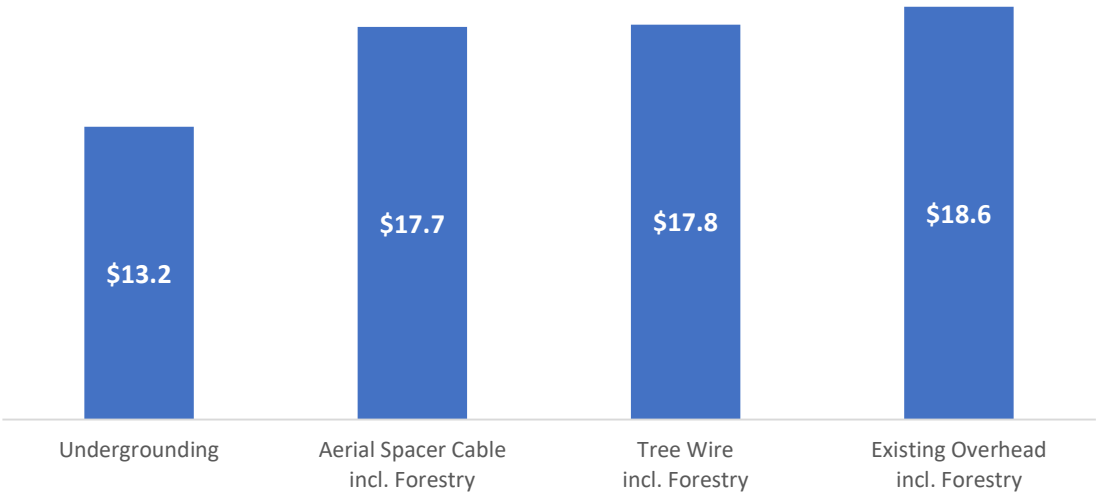
A. When using the SCT, undergrounding becomes the least cost option, as shown in Figure 25.

Q. What is the SCT and how is it impacted by undergrounding?

A. The SCT is an alternate methodology used to evaluate utility programs and their impact on society as a whole. Although it is not applicable to all utility programs, it could be applied to the undergrounding program to provide a comprehensive evaluation of benefits that are not captured in the UCT. Given the long-term value provided to customers by undergrounding, and the avoided external costs of outages resulting from the improved resiliency provided by undergrounding, the SCT should be considered as a secondary tool in evaluating the value of undergrounding. In general, the SCT uses a lower discount rate, which assigns more value to long-term benefits provided by undergrounding, and it also includes the customer cost of outages as calculated with the ICE Calculator. When taking the long-term and society-wide perspective into consideration, undergrounding yields better value to customers than the alternatives.

FIGURE 25

PILOT PROJECTS PRESENT VALUE OF UNDERGROUNDING AND ALTERNATIVES WHEN INCLUDING SOCIETAL COST OF CUSTOMER OUTAGES - $ MILLIONS



Q. Are the results of the SCT comparable to the UCT?

A. No. Please note that the PVRR in the SCT and the PVRR in the UCT cannot be compared directly to each other. The values in the UCT provide one means of comparison of the alternatives, and the values in the SCT provide another means of comparison.

Q. What other lessons has the Company learned from this pilot?

A. Based on the range of actual costs incurred in the pilot projects, the Company has learned that in addition to the selection criteria established in Case No. U-21389, it should also identify locations where undergrounding costs are likely to be lower. In comparing the Saugatuck and Newaygo results, the Company understands it can now prioritize undergrounding work on circuits that meet its selection criteria and where construction is simplified by minimizing the use of boring as the primary undergrounding technique, avoiding the need to underground large amounts of secondary, especially under the roadway, and avoiding customers who have a large number of unmarked private utilities. It is clear that many undergrounding projects, if in the right locations, are competitive with other non-undergrounding options, and undergrounding carries the added substantial benefits of greatly improved reliability and resiliency, plus forestry work is then no longer required.

Q. How will undergrounding compare to the alternatives when at scale?

A. Based on the lessons learned in project selection, the Company is better positioned to identify economically competitive projects, unlike the one completed in Saugatuck. At scale, the Company expects to continue to perform underground conversions at the originally projected cost of approximately $400,000 per underground mile.

At this cost, the Company would expect undergrounding to be comparable to the alternatives using the UCT, without taking into consideration the societal costs and benefits. Using the SCT, undergrounding at scale will be approximately 30% more cost effective than the alternatives of Aerial Spacer Cable and Tree Wire.

Q. Why is it important to consider the costs of the pilot when at scale?

A. It is important to evaluate the relative costs and benefits of undergrounding at scale, because an analysis that includes only the pilot itself would have skewed results since it would not make adjustments to account for the lessons learned in the pilot.

As discussed above, these lessons learned allow the Company to develop a more economical program than the initial test cases conducted in the pilot that will yield benefits to customers at scale.

FIGURE 26
PVRR OF UNDERGROUNDING AT SCALE AND ALTERNATIVES - $ MILLIONS

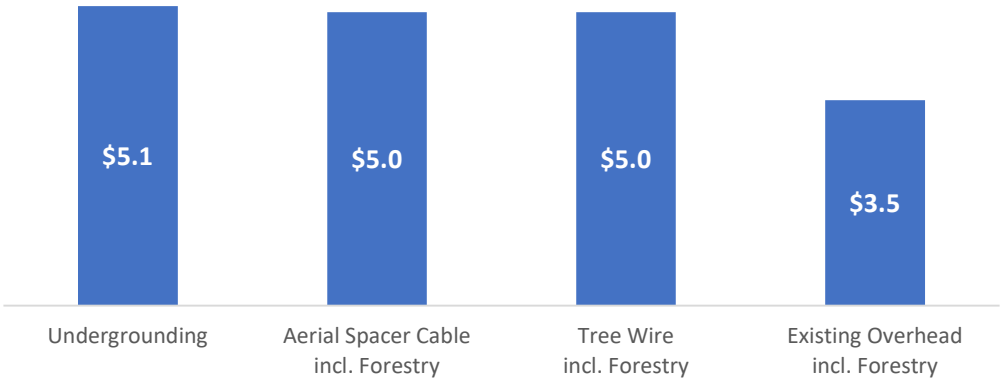
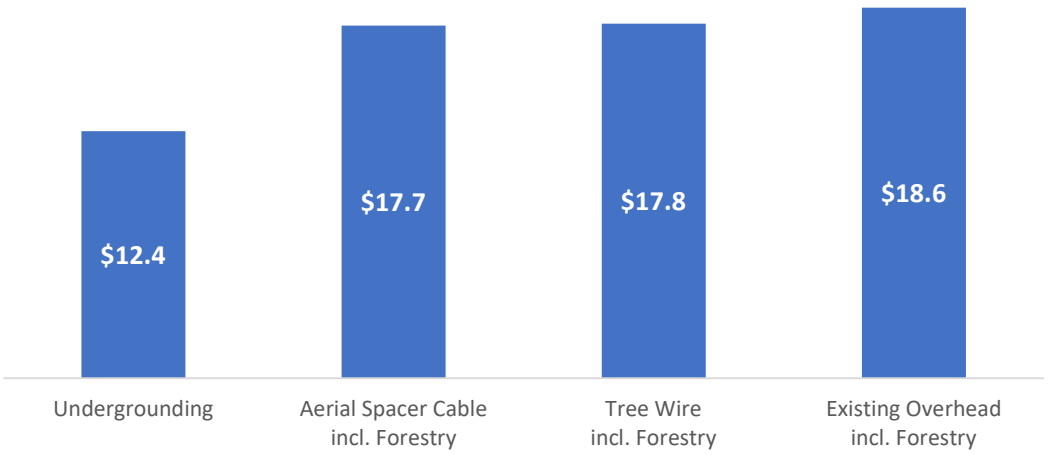


FIGURE 27
PRESENT VALUE OF UNDERGROUNDING AT SCALE AND ALTERNATIVES WHEN INCLUDING SOCIETAL COST OF CUSTOMER OUTAGES - $ MILLIONS



Q. How do the pilot and scaled costs of undergrounding compare to those cited in Case No. U-21122?

A. With an average cost of $423,000 per mile for the pilot and $400,000 per mile when at scale, the Company is able to convert overhead to underground for nearly 50% less than the $974,000 per-mile maximum cost that the Company assumed in its October 1, 2021, report in Case No. U-21122. Both costs are also less than the $626,000 per mile average cost cited in the same document.

Q. What reliability benefit is undergrounding expected to provide?

A. Based on work conducted by peer utilities, most notably WEC Energy Group and Alliant, the Company would expect an improvement in reliability of 90% or more.

Any conductor that is not undergrounded, when in an area with trees, will always be exposed to trees and susceptible to outages during severe weather. As shown later in Figure 44, trees continue to drive a significant proportion of the Company's LVD SAIDI.

FIGURE 28
OUT OF RIGHT OF WAY TREE IMPACTING OVERHEAD LINE



Q. What is the Company proposing regarding undergrounding in the instant case?

A. The Company is proposing 50 miles of undergrounding in the test year, based on the positive results of the pilot. As a result of the pause in the program, as ordered in Case No. U-21585, the Company will not be fully up to the scale outlined in the Reliability Roadmap in the upcoming test year.

Q. How does the Company plan to scale undergrounding?

A. The results of the pilot show that undergrounding is economically competitive, as described above. Given the results of the pilot, the Company intends to scale the program to 400 miles per year by 2028.

Q. Why is it important for the Company to continue undergrounding conversions?

A. The Company is often compared to similarly situated utilities like those in Liberty's Report, Part I, Chapter VI, which have larger percentages of their distribution systems underground. Because of the size of the Company's distribution system, more miles need to be undergrounded to better align with the Company's peers, on a percentage of system undergrounded basis, and to provide customers with resiliency benefits comparable to

these similarly situated utilities. On top of its sheer size, given the inclement nature of lake-effect weather, as noted by Liberty, the Company must invest in converting a minimum of 2,000 to 9,950 additional miles to compare to regional peers and to provide our customers with better reliability.

Objective: Clean and equitable grid

Q. How does the Company's distribution strategy support a clean and equitable grid?

A. The Company's distribution strategy is aligned with overall clean energy goals that involve increasing sustainability and reducing waste. The Company also continues to execute on a detailed strategy to understand the distribution reliability experience of EJ communities, and to address any inequity found to exist.

Increasing Sustainability and Reducing Waste

Q. How does the Company's distribution system support the Company's objective to increase sustainability and reduce waste?

A. In addition to providing Consumers Energy's customers reliable electric delivery service, the Company's distribution investments are also designed to help facilitate the transition to cleaner energy resources by integrating and optimizing DERs such as rooftop solar, as well as EVs, onto the system.

The Company's CVR investments reduce system losses, helping the Company meet load demand with less need for generation. The Company is considering sustainability through a broader scope by also including EJ factors in its distribution planning. This focus will address not only more equitable outcomes for customers, but also will lead to improved understanding of where the distribution system has sufficient hosting capacity to accept new distributed generation like solar.

Finally, the Company continues to ensure its investments are right-sized and appropriately targeted to avoid wasteful overbuilding of the system.

This can be seen, for example, in how the Company's Capacity Program investments are designed to address reasonably known and foreseeable load growth amounts without building more than is needed.

Q. How is the Company preparing to integrate and optimize DERs?

A. As technology matures and expands to more complex, larger, and widespread applications of DERs, incremental steps to gain expertise around DER deployment is the most sensible approach. The Company is laying the groundwork for this through its DER Optimization initiative, detailed in Company witness McPhail's testimony. As this is rolled out in the coming years, it will allow the Company to manage and coordinate Company and third--party owned DER assets, applying best practices and lessons learned to deliver solutions best suited for Michigan and customers. The DER Optimization initiative is more important than ever, since the statutory distributed generation cap was increased from 1% of utility load to 10%. The Company will need DER Optimization to ensure it can manage that higher level of distributed generation on its grid.

The Company is also pursuing a grant through the Infrastructure Investment and Jobs Act ("IIJA") to begin deploying distributed artificial intelligence ("AI") modules on residential electric meters to quickly analyze high volumes of data to detect and classify anomalies, and improve management of distributed assets. I discuss this further later in my direct testimony.

Q. How is the Company planning for the rise in EVs on the distribution system?

A. As discussed in Company witness Jeffrey A. Myrom's direct testimony, the Company is working to optimize load from up to 1 million EVs in its service territory by 2030 in support of the State of Michigan's policy goals. As noted in the Reliability Roadmap, the Company's current modeling indicates the highest levels of customer technology adoption, like EVs, will likely materialize on specific circuits, and while a limited number of circuits may start to approach their capacity thresholds by 2030, the Company's system is not likely to experience broader issues until closer to 2050.

Q. Is the Company doing any other work in the area of increasing sustainability or reducing waste?

A. As more customers adopt new technologies like DERs and EVs, hosting capacity will become a more prominent issue on the system, and hosting capacity analyses ("HCA") will be important in addressing any concerns that arise. HCA is defined as "the amount of DERs that can be accommodated without adversely impacting operational criteria, such as power quality, reliability, and safety, under existing grid control and operations and without requiring infrastructure upgrades."[16] DERs interconnect to the distribution system through a Commission-regulated process. HCAs can improve and streamline this process by identifying locations on the system with a high probability of accommodating DERs. While resource-specific analyses are still required with an HCA, an HCA can help customers and DER developers avoid proposing interconnections and incurring study costs in areas that are not suitable for DERs.

[16] MPSC Case No. U-20147, August 20, 2020 Order.

Q. What is the Company's recent history with HCAs?

A. In 2020, the MPSC directed the Company to pursue a "phased" approach to developing HCAs, with two primary phases:

- Phase I: A base-level approach with a zonal go/no-go map; and
- Phase II: Specific, detailed analyses on areas of the distribution system with high DER penetration, incorporating this information into a more detailed map with circuit voltage-level information as DER penetration continues to increase.

The Company completed a Phase I analysis and reported the initial results in its 2021 EDIIP filing, with a detailed description of Phase I methodology.

Since that time, the Company has updated its Phase I analysis as system conditions have changed, and the Company maintains a publicly available updated version on its website.

Q. What does the Company plan to do regarding HCAs in the near future?

A. The Company expects to have a more detailed Phase II analysis available by the second half of 2025. For its Phase II analysis, the Company will be able to use maximum load data from 2024 to create a snapshot of detailed hosting capacity information. This analysis relies on the Distribution Resource Integration and Value Estimation ("DRIVE") tool developed by EPRI, although in the future the Company may evaluate using other platforms if appropriate. Because manual analysis is still required with current capabilities, Phase II maps will be detailed but will not be updated in real time. Phase II hosting capacity maps will show much more detailed circuit information than the existing Phase I maps.

Addressing Distribution Equity

Q. How has the Company considered EJ factors in its distribution planning?

A. In the Settlement Agreement in Case No. U-21224, the Company agreed with the other parties that in future versions of the EDIIP and/or future rate cases, the Company would

study reliability performance and hosting capacity on circuits that overlap with EJ communities, which were defined as "census tracts that are above the 80th percentile on the MiEJScreen Overall Score." Since that time, the Company has engaged in ongoing, increasingly detailed, analysis of distribution system performance in EJ communities, which I detailed in testimony in Case Nos. U-21389 and U-21585.[17] Those analyses have built on one another, and each remains valid even as the Company has deepened its understanding. The analyses presented in Case Nos. U-21389 and U-21585 indicated that (a) on a systemwide basis, the Company's EJ communities have comparatively good reliability, but (b) there are particular EJ communities that do face reliability challenges, and given their socioeconomic vulnerabilities the Company intends to direct specific new investments to those communities to improve their reliability. In my rebuttal testimony in Case No. U-21585, I introduced the Company's plan to accomplish this goal, which is being presented in more detail in the instant case as the Vulnerable Communities Resiliency Plan.

Q. What is the Vulnerable Communities Resiliency Plan?

A. The Vulnerable Communities Resiliency Plan will make targeted strategic investments on EJ circuits with a goal of ensuring that every EJ circuit in the Company's service territory has SAIDI, including MEDs, that is in the second IEEE quartile or better. In other words, the Vulnerable Communities Resiliency Plan will ensure that no EJ circuits experience worse than industry average reliability, and it will do so including MEDs to account for the actual experience of those customers. The Vulnerable Communities Resiliency Plan will

[17] For these analyses presented in prior cases, please refer to pages 48 and 49 of my direct testimony in Case No. U-21389; pages 2 through 16 of my rebuttal testimony in Case No. U-21389; pages 45 through 61 of my direct testimony in Case No. U-21585; and pages 5 through 19, 23 through 25, and 35 through 39 of my rebuttal testimony in Case No. U-21585.

target EJ circuits, not EJ census tracts, because electrical geography (represented by circuits) does not always align with political geography (represented by census tracts). Circuits do not neatly follow census tract boundaries, and since investments are based on circuits (or zonal subsets of circuits), the Company cannot directly invest in "census tract reliability." Since every circuit serving an EJ census tract is an EJ circuit, investing in EJ circuits ensures the Company invests in every EJ census tract.

Q. What investments does the Company propose as part of the Vulnerable Communities Resiliency Plan?

A. Over a period of several years, the Vulnerable Communities Resiliency Plan will include incremental investments that align with investment types that already take place in the Company's Reliability capital program, particularly in LVD Lines Reliability and Resiliency. The total planned investments are as follows:

- Fractionalization: $200 million of total investment
  - 6 new substations – one for each EJ circuit with over 3,000 customers
  - 133 new circuit exits – one for each EJ circuit with over 1,000 customers
- LVD line rebuilds: $350 million of total investment
  - Rebuild 665 miles of primary LVD circuit to create a high-reliability mainline three-phase (i.e., aerial spacer cable or underground, based on local conditions)
- Other work: $50 million of total investment
  - 400 new reclosers to ensure no protective zones exceed two miles in length
  - 335 new switches (i.e., one every mile)
  - Approximately 3,000 additional fuses

Q. Will all these investments be incremental to what was outlined in the 2023 Reliability Roadmap?

A. The new substations were already included in the Reliability Roadmap. The remainder of the investments were not included in the 2024-2028 timeframe in the 2023 Reliability Roadmap. It is crucial to emphasize the Company is *not* proposing to take reliability investments already in the 2023 Reliability Roadmap and re-direct those to focus on the Vulnerable Communities Resiliency Plan, which would disadvantage customers in other parts of the Company's service territory. The Company will maintain its planned reliability investments, and then perform these targeted EJ investments in addition to those.

Q. What specific investments in the Vulnerable Communities Resiliency Plan are included in the instant case?

A. Proposed test year projects for the Vulnerable Communities Resiliency Plan are included in Company witness Partlan's project list exhibit, and can be found in Exhibit A-167 (JMP-2), page 22. These investments represent a total of $30,000,000, the first tranche of investments in the plan noted above.

Q. How does the Vulnerable Communities Resiliency Plan interact with the "EJ flag" in Grid Archetypes that was presented by the Company in the 2023 Reliability Roadmap?

A. In general, the Vulnerable Communities Resiliency Plan should supersede the EJ flag. The purpose of the EJ flag was to indirectly influence the planning and prioritization process to make sure that EJ circuits were not ignored. The Vulnerable Communities Resiliency Plan

identifies all EJ circuits, particularly those with poor recent reliability performance, and simply steers direct reliability investment into those circuits.

Q. How has the Company analyzed the reliability experience of EJ communities?

A. The Company has conducted several analyses of EJ reliability, which were presented and discussed in detail in Case Nos. U-21389 and U-21585. In its order in Case No. U-21389, the Commission directed the Company to also conduct a regression analysis related to EJ reliability. The Company spent considerable time in 2024 studying this issue, and did not present a regression analysis in Case No. U-21585, but did spend time in dialogue with MPSC Staff and other key intervenors.

In its final Order in Case No. U-21585, the Commission directed the Company to also include information about residential shutoffs in its regression analysis. In the first quarter of 2025, the Company has conducted the required regression analysis.

Q. Please describe how the regression analysis was conducted.

A. As noted above, the Company spent time in dialogue with Staff and other intervenors in 2024 about what a regression analysis should consider and how it should be structured. The Company also sought input and lessons learned from other utilities who have performed similar analyses in recent years. Based on this input, the Company determined it would need to retain a third-party consultant to assist with the analysis, and developed a request for proposal that was issued for competitive bidding. Once a consultant was hired, the consultant's representatives took part in additional dialogue with Staff and intervenors on analysis design and early analysis results. The analysis considered widespread types of Company data as well as publicly available data, particularly on socioeconomic and demographic issues. The full analysis, with its methodology, is being provided in this case

as Exhibit A-135 (MPK-25). All of the underlying data that was used in the regression analysis is also being provided in this case as workpaper WP-MPK-1, which will allow other interested parties to review the analysis and conduct their own analyses if desired. In addition to this data, the regression analysis also made use of other publicly available data, and the report in Exhibit A-135 (MPK-25) describes how this data was obtained and how it could be obtained by other parties. All of this data, and the analysis itself, should also address the other EJ-related data requirements promulgated by the Commission in its order in Case No. U-21389.

Q. What results did the regression analysis show?

A. As described in detail in Exhibit A-135 (MPK-25), a single regression analysis was not performed. Instead, a large number of different types of statistical analyses were performed, including different types of regression analyses, to evaluate questions of differing reliability performance and differing experiences with involuntary shutoffs across areas of differing socioeconomic status and other conditions. A large number of individual analyses yielded statistically insignificant results, making it difficult to discuss all of the results in a fully comprehensive manner. However, it is possible to group the analyses into a few categories and discuss some of the statistically significant results in that manner.

First, multiple analyses compared average reliability of different types of census tracts, comparing EJ vs. non-EJ tracts; urban and rural tracts; low-income and high-income tracts; and high-percent-minority vs. low-percent-minority tracts. These analyses indicated that, when statistically significant differences exist, it is consistently the EJ, urban, low-income, and high-percent-minority tracts that have better reliability. This is

congruent with the Company's own analysis as presented in Cases Nos. U-21389 and U-21585.

Second, multiple regression analyses studied census tract-level reliability. Where statistically significant correlations exist, these analyses showed that higher MiEJScreen scores are correlated with improving reliability. However, these analyses also showed instances where increasing poverty levels and increasing unemployment rates are correlated with worsening reliability, in terms of SAIDI and SAIFI as well as outage duration.

Third, multiple regression analyses studied circuit-level reliability, with particular attention to classifying circuits by whether they serve EJ census tracts; whether they serve urban census tracts; whether they serve low-income census tracts; and whether they serve high-percent-minority census tracts. These analyses found no significant correlation between reliability and whether a circuit serves urban, low-income, or high-percent-minority census tracts. However, they did find instances where circuits serving EJ census tracts are more likely to experience customer interruptions, as measured by SAIFI excluding MEDs.

The regression analysis findings related to residential shutoff rates will be discussed by Company witness Jessica R. Byrom. I will discuss my conclusions regarding the equity of reliability below.

The regression analyses, and their conclusions, are further summarized in the presentation provided as Exhibit A-138 (MPK-28).

Q. What conclusions do you draw from the regression analysis regarding equity of reliability?

A. As I have already noted, a large number of individual analyses performed in this exercise returned no statistically significant results. The results discussed above represent those fairly few instances where clear results could be identified. It is not clear that regression analysis as a whole is well-suited to analyzing the electric distribution system in this manner.

With that caveat, the first set of analyses mentioned above – evaluating whether one set of census tracts or the other have better reliability – seem to confirm the Company's analyses as presented in Case Nos. U-21389 and U-21585. There is nothing apparently systemic or unique about EJ census tracts (or other potential groupings of disadvantaged census tracts) as a whole that give them worse reliability, since they average better reliability than other census tracts.

Still, the regression analyses of census tract-level and circuit-level reliability also indicate that there are some ways to interpret data that indicate that there are certain areas within EJ communities that do face worse reliability. This confirms the crux of the Company's analysis as presented in rebuttal in Case No. U-21585 (which is also discussed in the Reliability Roadmap in Exhibit A-129 (MPK-19) in the instant case), which identified individual EJ circuits with poor reliability. That analysis in Case No. U-21585 led the Company to develop the Vulnerable Communities Resiliency Plan. These regression analyses of census tract-level and circuit-level reliability further underpin the

need to make targeted investment in those EJ communities that do have poor reliability, given their particular vulnerability to frequent and/or extended outages.

Q. Has the Company produced any maps to graphically represent reliability in EJ communities?

A. The Commission's Order in Case No. U-21389 directed the Company to work with Staff to develop a means for interested parties to access Geographic Information System ("GIS") data from the Company, and the Company undertook this effort during late 2024 and early 2025. This process has resulted in two new public outputs. First, the Company has posted interactive GIS maps to its public website that show EJ circuits overlaid with EJ census tracts in the Company's service territory, showing SAIDI and SAIFI by circuit, with and without MEDs. These maps can be accessed at: https://experience.arcgis.com/experience/1d84e089ff5e4a2382df340d15689488.

Second, the Company has created an online form on its public website that allows interested parties to access GIS data. This form can be accessed at: https://www.consumersenergy.com/about-us/electric-generation.

Q. How has the Company worked to improve storm restoration in EJ communities?

A. In early 2025, the Company created a dashboard for use during restoration activities that highlights outages on circuits that impact EJ Communities. This dashboard helps to ensure the Company is maintaining a focus on the customers who are some of the most impacted by outage events caused by storms.

Q. Has the Company performed any hosting capacity analyses related to EJ communities?

A. Yes. This was another stipulation agreed to in the Settlement Agreement in Case No. U-21224. Prior to this filing, the Company had only completed a hosting capacity analysis for its entire system that determined whether a circuit has 2 MW of hosting capacity, and this information was presented in Case Nos. U-21389 and U-21585. Since the Company is moving to a more detailed Phase II hosting capacity analysis in 2025, as discussed above, that new analysis will also include the hosting capacity of EJ circuits. While that Phase II analysis is still in progress, the Company is providing its preexisting hosting capacity analysis for EJ circuits in Exhibit A-137 (MPK-27).

Objective: Provide competitive, affordable rates

Q. What avenues is the Company pursuing in its distribution strategy to deliver competitive, affordable rates for customers?

A. The Company is seeking federal government funding for reliability and resiliency projects through the IIJA to leverage federal funds to achieve reliability goals.

Q. How will seeking federal funding through the IIJA help the Company optimize system costs?

A. The IIJA offers federal funding to support various infrastructure projects throughout the United States, including certain types of utility infrastructure. If the Company is able to obtain federal funding to support distribution infrastructure investment, then the portion of the costs of that infrastructure funded by federal grants would not be passed on to customers.

Q. Has the Company been selected for any federal funding through the IIJA?

A. Yes. To date, the Company has been selected for four grants related to grid reliability and resiliency, and is in the process of negotiating with the DOE on the final terms:

- **Section 40101(c): Grid Resilience Program.** Under this section of the IIJA, the Company was selected for a $100 million grant running through 2028. This grant could provide the Company with approximately $20 million each year in matching funds to perform sectionalization and circuit improvement work in federally-defined disadvantaged communities ("DACs").

- **Section 40101(d): Grid Resilience Grants.** According to the Michigan Department of Environment, Great Lakes, and Energy ("EGLE"), Michigan is expected to receive a $38 million grant for "preventing outages and enhancing the resilience of the electric grid." The Company was selected by EGLE to potentially receive $4.05 million as part of this grant.

- **Section 40101(d): Grid Resilience Grants (state and tribal program).** Under this section of the IIJA, the Company was selected by the Nottawaseppi Huron Band of Potawatomi tribe to implement a $500,000 grant to perform pole top rehabilitation and other HVD upgrades to improve reliability.

- **Section 40107: Grid Resilience and Innovative Partnerships**. The Company is partnering with Utilidata, the Electric Power Research Institute ("EPRI"), GM Energy, and the University of Michigan on this grant, which is worth $19.9 million. The Company was selected to receive this grant in October 2024.

Q. Has the Company received any funding related to the grants?

A. No. The Company has not yet received funding related to the grants as the Company is still in negotiations with the Department of Energy on the terms and conditions.

Q. Will the Company have to match funds provided by the federal government?

A. Most, if not all, of the funding opportunities being offered through the IIJA require a grantee percentage match. Recipients of the offered funding must match a varying percentage of the funding awarded to use the grant dollars. In the case of the Section 40101(d) and the two Section 40101(c) grants listed above, the Company expects to match the funds provided by the federal government. Because of this provision, the full costs for the associated work are included in my capital exhibits, and the portion being provided by

the federal government is listed as negative dollar amounts in Exhibit A-12 (MPK-1), Schedule B-5.7, lines 9 and 19, and itemized in Exhibit A-121 (MPK-11).

Q. Why is the Section 40107 grant not included as having the federal government providing funding?

A. The Section 40107 grant is not far enough along in negotiations for the Company to be certain of project timing and funding from the federal government. As such, the Company is not seeking reimbursement of costs, and is not indicating any grant funding from the federal government in this instant case.

Q. Please provide more details regarding the work that will be done related to the grant under Section 40101(c) of the IIJA.

A. Under Section 40101(c), the Company plans to perform targeted reliability improvements directed toward Michigan's vulnerable communities. Funds are expected to be used to increase sectionalizing on circuits, minimizing the number of customers impacted by a single fault, and constructing new tie lines for circuits currently with no ties to neighboring circuits. ATR loops between these circuits and their new ties would also be added. The new tie lines would harden the system at the ends of circuits and create three-phase load addition capabilities where currently only single phase exists.

Q. Please provide more details regarding the work that will be done related to the grants under Section 40101(d) of the IIJA.

A. For one of the grants under Section 40101(d), the Company expects to perform rehabilitation work on the Athens HVD line in 2025, and on related nearby LVD circuits in 2026, to improve reliability for the Nottawaseppi Huron Band of Potawatomi tribe near Athens, Michigan.

For the other grant under Section 40101(d), EGLE has received a block of federal funding. The Company expects $4 million in grant funding from this block through EGLE to perform undergrounding of service drops and upgrades of secondary voltage lines in EJ communities.

If the Company receives this funding from EGLE as expected, the Company expects that 372 residential customers will be directly impacted through secondary and service work. These customers are in Kalamazoo, Grand Rapids, and Flint. The areas of focus include transformers on circuits in communities with above average MiEJScreen scores that had multiple outages from 2021 through 2023 (targeted work is in census tracts that are at least at the 60th percentile per MiEJScreen, with much of it at the 80th percentile or higher).

This project work is estimated to save 288,000 customer-outage-minutes annually, based on an estimated 80% reduction in outages on the secondary circuits and services feeding homes.

Q. Please provide more details regarding the work that will be done related to the grant under Section 40101(c) of the IIJA.

A. The purpose of this grant will be to use AI modeling in innovative ways to create value for customers in historically disadvantaged communities and in areas of high DER penetration. Specifically, the Company would deploy 18,000 distributed AI modules on residential electric meters. These AI modules can quickly analyze high volumes of data to detect and classify anomalies, and improve management of distributed assets, which will be particularly valuable in locations with higher EV penetration. Locations would be selected based on:

a) circuits with reliability issues; and

b) circuits and transformers with DER penetration.

For this project, the Company will work with General Motors, Utilidata, EPRI, and the University of Michigan Transportation Research Institute. The Company is not yet seeking rate recovery of any costs related to this grant.

Q. Will the Company continue to seek recovery of costs or provide refunds for funding awards related to IIJA projects?

A. As discussed earlier in my testimony, the Company is accounting for the costs of the projects, and the offsetting awards from the federal government, as shown in my capital exhibits.

The Company will continue to seek the use of a regulatory asset or liability to defer the revenue requirement of IIJA funding expenses above or below amounts included in rates, in accordance with the Commission's guidance in Case No. U-21227, for projects the Company has applied for but has not yet received notification of a selection decision from the federal government.

Q. How will the Company continue to update the Commission on its continued efforts to pursue IIJA funding for distribution-related projects?

A. The Company will continue to update the Commission biannually in Case No. U-21227, most recently on December 30, 2024. The next update is planned to be filed on June 30, 2025. Further biannual updates are planned to be filed on December 31 and June 30 of every year until further ordered by the Commission, or until all applicable funding opportunities under IIJA are closed to applications.

Q. What information is included in the biannual updates?

A. The biannual updates include a narrative summary of which opportunities the Company applied for, including citations to individual programs sought, what stage of the grant process that application is in, which applications have been approved and awarded funding, and others that may be in process.

IV. CAPITAL SPENDING OVERVIEW

Q. How does the Company ensure that its electric distribution capital planning process selects the correct alternatives?

A. The Company is committed to making investments in its distribution system to ensure they will deliver clear and cost-effective customer benefits, and not just making investments for their own sake. For traditional investments on the distribution system, the Company generally uses a "least--cost, best-fit" analysis to identify the optimal project. When an asset has failed, or is in poor health and at risk of failing, or if it is projected to be overloaded soon, or must be relocated, the Company has no alternative but to address the issue to ensure customers continue receiving reliable service. The Company identifies the least costly solution that will satisfactorily solve the issue. The Company has used more extensive benefit-cost analyses for some non-traditional investments.

Q. What do you mean by "traditional" and "non-traditional" investments?

A. In the context being used here, the Company defines "traditional" distribution investments as investments in components of lines (such as poles, pole tops, conductor, and certain devices), substation infrastructure, and other related items, across a variety of investment programs. Conversely, the Company defines "non-traditional" distribution investments as those in newer technologies, such as those covered in Grid Automation, or in certain pilot programs.

Q. Can you provide more detail regarding how "least-cost, best-fit" analysis works?

A. Yes. The overarching principle of least-cost, best-fit ("LCBF") is that once the Company has identified an issue on the distribution system that must be addressed, the Company identifies and chooses a solution that satisfactorily fixes the issue for the least cost.

The identified issue may be a failed piece of equipment, a circuit or subset of a circuit with persistently poor reliability, an overloaded piece of equipment, an asset that must be relocated, or any number of other issues. LCBF analyses ensure investments are both cost-effective and meet the necessary functionality and capability requirements.

LCBF analyses themselves are not necessarily used to rank and prioritize projects against one another. As discussed elsewhere in testimony, particularly by Company witnesses Partlan and Hayward, the Company prioritizes the assets that need to be addressed based on a variety of inputs, depending on the specific investment program. Once assets have been prioritized and the Company has determined where work is needed, LCBF is used to select the type of project to execute in that location.

LCBF is commonly recognized in the utility industry as an appropriate means for evaluating traditional reliability investments. It is important to note that LCBF does not always lead to the Company selecting the lowest cost alternative outright, because the "best fit" part of the principle must also be considered.

Q. In identifying a solution, how does the Company compare different potential projects against one another?

A. For some smaller projects, the Company may identify a solution based on what has been known to work in similar circumstances in the past, applying the least-cost, best-fit principles discussed above. For many larger projects, the Company uses a more formal

process to compare proposed electric distribution investment against alternatives, developing a "concept approval" to test and demonstrate why the selected project is reasonable and prudent, ensuring strong and robust justification for selected electric distribution projects.

For example, concept approvals for the Company's top 25 distribution projects are provided with Part III Requirement 142 in this case. The general structure of a concept approval includes the following:

1. Identification of the problem;
2. Identification of alternatives to address the problem;
3. Determination of costs and benefits of the alternatives;
4. Selection of best alternative;
5. Approvals; and
6. Revisions, if necessary (i.e., if costs and/or project scope change substantially following approval).

Q. Please explain the Company's process for concept approvals.

A. The process begins by the Company's planning engineers identifying problems (such as by reviewing reliability data and projected overloads) and system needs (such as by reviewing customer or third-party requests).

Once the problems or needs are identified, the planning engineers develop a list of alternative solutions. For each alternative, costs, benefits, and intangible considerations are developed. Although the planning engineer is responsible for this process, there is significant collaboration with design engineering, construction, and operating personnel in each phase of the process.

The alternatives are then compared against each other, and the planning engineers identify a selected alternative. The Company identifies selected alternatives using an LCBF, as discussed above. In other words, investment that yields the best fit is intended to produce the maximum benefit at the least cost. This ensures the Company's investment is optimized for customer benefit.

The final step of the process is to document all the information in a concept approval document that is routed through management for approval. In most cases, concept approval documents go to a program manager for review and approval, but could require additional approvals, depending on the projected cost of the project.

Q. Please provide an illustrative example of the concept approval process.

A. Au Gres Township passed a medical marijuana ordinance in 2018 resulting in five customers requesting electric service for marijuana grow facilities totaling 2.8 megavolt amperes ("MVA"). The electric system in that area was not capable of supporting an incremental 2.8 MVA of demand.

In response to these requests, the Company's planning engineers reviewed the surrounding electric system to determine conceptual alternatives for serving the incremental demand. The concept approval document included four alternatives involving different locations for substations connected at different voltage levels.

For each alternative, the Company developed a projected cost, feasibility, and timeline based on performing similar work in the past. In addition to the costs, the Company's planning engineers examined other considerations for each alternative, including availability of ROW, reliability impact, and ability to meet timeframes requested by the customers.

A selected alternative was identified that represented the best fit project to provide reliable service to the Au Gres area. The problem statement, alternatives, and selected alternative were documented in the Company's concept approval form and routed to management for review and approval. Once approved, the selected alternative was commissioned for ROW acquisition, and substation and line design and construction.

Soon after commencing work on the selected alternative, ROW challenges and new customer load requests totaling 6.8 MVA necessitated a revision to the selected alternative as it was apparent the originally selected alternative was no longer viable at the approved cost. Additionally, easements for a new 138 kV line were unable to be obtained along the proposed route, and it was determined a significant number of wetlands were present in the area. Lines passing through wetlands require a lengthy permitting process and often costly mitigation work. A revised concept approval with this new information and costs was needed.

The revised concept approval document showed the changes from the original document to concisely convey them to management. These changes included updating the problem statement, including new or revised alternatives, and refining the costs and benefits. The revised concept approval followed the same process as the original, with the Company's planning engineers developing alternatives, costs, and benefits, and then seeking management approval of the selected alternative.

The newly included fifth alternative for the Au Gres area was the selected alternative because it was a solution to both serve the new incremental customer demand and improve reliability to the area.

The revised concept approval and selected alternative did not pass through the approval process without questions. Discussions between management and planning engineers led to the identification of improvements within the selected alternative. Specifically, the circuit configuration was refined to further improve reliability to the area customers. These circuit configuration improvements were included in the concept approval for documentation purposes, but the selected alternative did not change.

The revised concept approval was ultimately approved, and the newly selected alternative was commissioned for ROW, design, and construction.

Q. How do customers benefit from the concept approval process?

A. The concept approval process provides a rigorous approach and governance structure to identifying problems and needs, alternative solutions, and recommended alternatives. It provides for exceptional peer review and management oversight to ensure the Company's investment plans are well justified, reasonable, and prudent for customers.

Q. Does the Company use any other regular practices to identify areas of the system that require prioritized investment?

A. Yes. The Company has also implemented a Distribution System Health Quarterly Operating Review ("QOR"). The QOR allows Company planners to go through a comprehensive review of the entire system, reviewing asset health of system components based on information gathered during inspections and maintenance activities. Gathered data informs the Company on an asset's health based on likelihood, consequence, and severity of an asset's failure, also known as that asset's risk. When assets are identified as being at-risk, the Company develops projects to address that risk proactively. The QOR

lets the Company monitor shifts in asset risk and ensures continued investment in the correct places based on the latest asset information.

By reviewing asset health data every quarter, the Company has the most up-to-date information on what investments will be needed (and how much investment will be needed) as projects are planned for the following few years.

The Company continues to make improvements to its QOR process so the review process provides increasingly better information. Company witness McPhail's projected Distribution Asset Management investments are crucial for these ongoing improvements.

Q. How does the Company classify its distribution capital investments?

A. The Company makes capital investments under two broad classifications, *unplanned* and *planned*, as outlined in Figure 29 below.

FIGURE 29
PLANNED AND UNPLANNED DESCRIPTIONS

Classification	Description	Programs included
Planned	Investments planned to proactively improve grid reliability through capacity upgrades, and investments in new tools and technology.	Reliability, Capacity, "Electric Other," Wildfire Risk Mitigation
Unplanned	Demand-driven, customer-driven, or other reactive needs.	New Business, Demand Failures, Asset Relocations

Each of these classifications correspond to one or more capital "Programs," and they are:

- Reliability;
- Capacity;
- New Business;
- Demand Failures;
- Asset Relocations;
- Electric Other;

- Vulnerable Communities Resiliency Plan; and
- Wildfire Risk Mitigation.

Each Program is in turn divided into several "sub-programs," and many sub-programs are divided into several "investment categories."

Programs can include spending on LVD, HVD, and Metro assets, but each sub-program and investment category is specific to a single asset classification. Company witnesses Partlan, McPhail, and Hayward each explain how investments are broken into sub-programs and investment categories under the seven overall programs identified here.

Q. What work is completed in the Reliability Program?

A. The purpose of the Reliability Program is to ensure the long-term safe and reliable operation of the distribution system, particularly by reducing system outages and hardening the system. This includes installing, upgrading, and rehabilitating LVD and HVD lines, LVD and HVD substations, Metro underground assets, and protective relay systems; it also includes investments to modernize the grid through Grid Automation.

Reliability Program investments are a major contributor to the Company's efforts to address deterioration. While other programs may replace deteriorated assets as a secondary consideration, many Reliability investments have the express purpose of doing so. Grid Automation investments are included in the Reliability Program because many of the automation capabilities delivered by Grid Automation improve reliability for customers. As discussed above, the Company is planning an increase in investment in the Reliability Program under the plan outlined in the Reliability Roadmap.

Q. What work is completed in the Capacity Program?

A. The Capacity Program is designed to:

1. Ensure that the HVD system can serve forecasted peak demand when all HVD facilities are in service;

2. Ensure that individual HVD facilities can be taken out of service during non-peak period without loading equipment beyond ratings or providing unacceptably low voltage;

3. Address LVD equipment overloads that have occurred; and

4. Proactively address LVD equipment that has run at a higher loading than rated for.

Additionally, the Capacity Program includes the CVR sub-program that puts that component of the Company's IRP into effect.

Q. What work is completed in the New Business Program?

A. The New Business Program includes the capital costs of connecting new commercial, industrial, and residential customers to the Company's distribution grid. This includes the costs of installing poles, conductor, transformers, meters, and in some cases, entire new substations. Because of the Company's obligation to serve customers, the Company generally is required to provide the requested interconnections if the customer meets the requirements set by the Company's tariffs.

Q. What work is completed in the Demand Failures Program?

A. The Demand Failures Program addresses issues related to customer interruptions or failures of equipment on the system. When equipment fails and customers are interrupted, the Company is obligated to fix the issue and restore customers as quickly as possible. The program also enables the Company to respond to day-to-day equipment failures, even if customers may not be interrupted. If the Company fixes failed equipment in this process, the capital expenditures take place in the Demand Failures Program.

Q. What work is completed in the Asset Relocations Program?

A. The Asset Relocations Program includes capital investments to relocate electric assets to accommodate road, building, and other third-party construction projects, including those requested by municipal governments, as well as internal Company projects.

Q. What work is completed in the Electric Other Program?

A. The Electric Other Program consists of additional capital investment to support the distribution system that does not fall into one of the other five programs.

Q. What work is completed in the Vulnerable Community Program?

A. This line item in my exhibits represents the work being done in the Vulnerable Communities Resiliency Plan that I described earlier in my direct testimony.

Q. What work is completed in the Wildfire Risk Mitigation Program?

A. The Wildfire Risk Mitigation Program is aligned with the Company's wildfire risk mitigation strategy that I described earlier in my direct testimony. In the instant case, the Company is not requesting recovery of any capital investment for the Wildfire Risk Mitigation Program, although the Company is seeking recovery of some O&M expenses.

Q. Referring back to Figure 29, please describe unplanned investments.

A. Several of the Company's capital investment programs respond to demand-driven, customer-driven, or other emergent needs. These investments are not strictly "unplanned," as the Company does anticipate it will have to make these investments to replace failed equipment, and to add new customer connections to the system. However, due to the emergent nature of these needs, the Company's investments can be difficult to plan with specificity in advance, because it is not possible to know the exact number of equipment failures that will occur or new customer connection requests that will occur, or where such

needs will occur. Instead, the Company forecasts the number of new business services that will be requested in the future based on historical service levels and projected growth rates, as further discussed in Ms. Partlan's direct testimony. The Company then applies a unit cost to these expected requests to develop a forecasted level of spending. These unplanned programs consist of New Business, Demand Failures, and Asset Relocations.

Q. Please describe planned investments.

A. In addition to the investments addressing emergent needs described above, the Company also plans investments further in advance to proactively improve the grid through reliability improvement projects, capacity upgrades, and investments in new tools and technology. These programs consist of Reliability, Capacity, Electric Other, and Technology.

Q. Are all investments in the planned programs identified and planned equally far in advance?

A. No. Individual projects vary widely in size, scope, cost, complexity, and other factors, and they correspondingly vary in how far in advance they are planned. For example, on the HVD system, substation and line rebuilds are large, complex projects with long lead times for design and construction work, so those projects are planned more than a year in advance. Conversely, individual pole replacements on the HVD system are comparatively simple, with lead times in the order of weeks, so the Company does not identify individual poles for replacement months or years in advance; instead, the Company identifies HVD lines on which it will inspect poles in advance, with an expectation that, based on historical inspection experience, a given number of poles inspected will require replacement.

Q. What capital projects does the Company expect to invest in during the bridge period and the test year?

A. Specific distribution projects for the bridge period and test year are discussed by Company witnesses Partlan, Hayward, and McPhail, and are identified in their exhibits.

Q. What information is included in these exhibits?

A. The exhibits include projects identified with scope, cost, location, benefit type, and benefits. Figure 30 below identifies quantifiable benefit types.

FIGURE 30
INVESTMENT BENEFIT DESCRIPTIONS

Benefit Type	How Benefits were Quantified
Customer-outage-minutes	Product of the number of customers that experience an extended outage of electrical service and the duration of outage measured in minutes.
Customers Impacted	Number of customers served by a project. In the case of commercial customers, the customers impacted are treated as "1."
NOTE: Not all projects have quantifiable benefits. Some projects in the Capacity, Reliability, and Electric Other programs are completed for regulatory compliance, operating efficiency, or based on the Company's obligation to serve.	

Q. What is meant by a "Customer-Outage-Minute" benefit?

A. *Customer-outage-minutes* (sometimes referred to as customer minutes interrupted or "CMI") is a mathematical product of the number of customers that experience an extended outage of electrical service, and the duration in minutes of that outage. These numbers are gathered through the Company's outage management systems for each outage. For example, a failure on the LVD system that interrupts electrical service to 100 customers for 170 minutes would accrue 17,000 customer-outage-minutes.

A reliability project will reduce this number by reducing the probability of failure leading to an outage, the duration of the outage, and/or the number of customers impacted

by the failure and subsequent outage. The planning engineer will determine the amount of savings based on both the historical outage data of that part of the system and the expected effectiveness of the solution selected. For example, if the historic average customer-outage-minutes of an LVD zone were 20,000 per year and the proposed project would reduce the probability of that outage by 70%, the customer-outage-minutes saved or avoided by completing the work would be 14,000 (70% of 20,000). In this way, the benefit of a distribution reliability project can be quantified.

Q. How do the Company's projected customer-outage-minutes in the instant case compare to the Company's SAIDI levels or projections about SAIDI in the future?

A. While there may be an indirect connection between customer-outage-minutes avoided and SAIDI, they are two separate things and should not be conflated. Customer-outage-minutes avoided is a way to model the future outages that *would likely* occur on a circuit, line, or substation if a project is not done and the asset were to fail. For some assets, especially substations, historical outages are generally infrequent, meaning their historical contribution to SAIDI is relatively low, and projects will not necessarily significantly decrease SAIDI in the future. However, substation failures are high-impact events when they do happen, so a substation project may have a high number of customer-outage-minutes avoided, because the project prevents a future failure and therefore prevents many future outages that would have otherwise happened.

In general, for any type of asset, investments to reduce the likelihood of future outages do have a large impact on the projected number of future customer interruptions that would happen absent the investments. For example, if the Company assesses that a transformer is at risk of failure, and failure would cause 10,000 customers to lose power

for 24 hours, the Company will conclude that replacing the transformer avoids those outages in the future, which is a reasonable assessment even if there have not yet been actual historical outages to consider. By considering projected customer-outage-minutes avoided in this manner, the Company can meaningfully compare the relative benefits of different potential projects.

Q. What is meant by a "Customers Impacted" benefit?

A. *Customers impacted* is the number of customers who are served by an asset or project and therefore would experience an outage of electrical service if this asset were to fail or would realize a benefit to reliability with its improvement.

Q. Does the Company propose to receive deferred accounting authorization in this case for the New Business, Demand Failures, and Asset Relocation programs?

A. Yes. While the Company attempts to project investment needs for the New Business, Demand Failures, and Asset Relocations programs, the largest factors influencing expenditures in these programs are externally driven. As a result, the Company requests that it be allowed to continue to defer the revenue requirement for any capital spending for these programs above what is included in rates, if the spending exceeds what the Commission approves in this case. The Company agrees to the same stipulations the Commission approved for deferred accounting treatment for these programs in Case No. U-21585. One of the stipulations is that the Company spend the full amounts approved by the Commission in the Line Clearing Program. As further described in the direct testimony of Company witness Stewart, the Company is proposing a "ramp-up" to achieve a five-year clearing cycle on the LVD system. Ms. Stewart bifurcates the total Line Clearing Program expenses between "total" and "baseline" O&M expenses. For purposes of the

aforementioned stipulation, the Company requests that the threshold be set on the "baseline" Line Clearing O&M expenses supported by Ms. Stewart.

Q. What risks would be created if deferred accounting were not authorized in the instant case?

A. If deferred accounting is not authorized for any spending in New Business, Demand Failures, and Asset Relocations that exceeds what the Commission approves, then the Company will be exposed to financial risk if increased investment needs materialize in those programs. Investment in all three programs is heavily driven by external factors, including customer requests the Company must address. Although the Company makes reasonable and best efforts to project investment needs in those programs, they cannot be projected with complete accuracy. As an illustrative example, the Company could project test year Asset Relocations investments of $50 million, based on a well-supported methodology, and the Commission could approve this amount for inclusion in rates. When the test year arrives, new and unforeseen Asset Relocations needs could emerge, driven by external factors, such that total Asset Relocations investments now total $55 million. In this hypothetical, the Company must make the incremental $5 million in investments. When deferred accounting is authorized, the Company has certainty that this incremental $5 million will be recoverable, even if on a deferred basis.

Conversely, without deferred accounting, this $5 million would be at risk. The Company must complete the Asset Relocations, but to keep overall investment levels in line with Commission approval, the Company would need to delay $5 million in investments in one of the planned programs, such as Reliability or Capacity. This would deprive customers of the benefits of those programs.

Furthermore, the Commission has not always approved 100% of the Company's projected investment amounts in these three programs for a variety of reasons.

If other parties argue the Company's projected investment levels in these programs are too high and the Commission agrees in a final Order, then deferred accounting supports recovery if investment levels materialize as the Company forecasted.

Deferred accounting has been approved by the Commission (through both approved settlements and orders in fully contested cases) in every rate case since Case No. U-20134, which covered a 2019 calendar test year. Since that time, deferred accounting has worked to provide for recovery of externally-driven investments that must be made and ensure the Company does not need to reduce investments in other programs that focus on proactively improving customer reliability.

Q. How did the Company identify areas of distribution investment to include in the IRM in this case?

A. The Commission provided partial approval of the Company's proposed IRM in Case No. U-21389, for a two-year period that will end on February 28, 2026. In the instant case, the Company is proposing to establish a continuing mechanism that will extend the IRM for an additional two years, consisting of the test year in the instant case and the year after that, meaning the continuing IRM would run until April 30, 2028. In the instant case, the Company is proposing to continue the IRM using the same investment categories the Commission approved in Case No. U-21389, and to add two new sub-programs, as discussed below. For all proposed IRM spending, the Company proposes to set the investment levels for those categories at or below those included in the test year in the

instant case. See also the discussion of the IRM in Company witness Myers' direct testimony.

Q. What investments are included in the proposed IRM?

A. The IRM investments previously approved by the Commission consist of the following sub-programs:

- *LVD Lines Reliability* - Targeted Circuit Improvements and Pole Replacements;
- *Resiliency* - Fractionalization; and
- *System Protection.*

In the instant case, the Company is proposing to also include the Repetitive Outages sub-program and the Vulnerable Communities Resiliency Plan in the IRM.

Q. Why is the Company proposing to include the Repetitive Outages sub-program in the IRM?

A. As discussed by Company witness Partlan, the Company's recent performance for CEMI-4 has not been meeting the Commission's Service Quality and Reliability Standards, and will not meet the standard at current investment levels. The Repetitive Outages sub-program is specifically designed to identify locations on the system where customers experience frequent outages and correct the underlying issues. The Company is proposing to increase investment in this sub-program, and including the expenditures in the IRM will provide additional assurance to the Commission and to customers that these funds will be spent on improving CEMI-4 to the Commission's standards.

Q. Why is the Company proposing to include the Vulnerable Communities Resiliency Plan in the IRM?

A. As discussed earlier in my direct testimony, the Vulnerable Communities Resiliency Plan is crucial for ensuring disadvantaged communities in the Company's service territory receive better than average all-weather reliability.

Including this spending in the IRM will provide assurance these expenditures will be directed to this important goal. Furthermore, in its final Order in Case No. U-21389, the Commission expressed a desire that any IRM should see investments deployed equitably, and that an IRM should not "exacerbate or perpetuate racial or socioeconomic disparities in service."[18] Including the Vulnerable Communities Resiliency Plan in the IRM will support this goal.

Q. What level of expenditure does the Company propose to include in the IRM?

A. Based on this discussion above, the proposed expenditure level is as follows:

FIGURE 31

PROPOSED IRM EXPENDITURES

Sub-Program/ Investment Category	Proposed IRM Expenditure
Lines Reliability – LVD ***(Targeted Circuit Improvements and Pole Replacements)***	$276,191,000
Resiliency – Fractionalization	$11,647,000
System Protection	$4,098,000
Repetitive Outages - LVD	$30,344,000
Vulnerable Communities	$30,000,000
Total	**$352,280,000**

[18] MPSC Case No. U-21389, March 1, 2024 Order, page 273.

Q. How do these proposed IRM expenditure levels compare to what was approved by the Commission in Case No. U-21585?

A. The proposed IRM expenditure levels for LVD Lines Reliability are greater than those approved by the Commission in Case No. U-21585, in line with the Company's total proposed test year investment amount in the instant case. LVD Repetitive Outages is newly proposed for inclusion in the IRM in the instant case, and the Vulnerable Communities Resiliency Plan is a newly proposed investment altogether. The proposed IRM expenditure levels for Resiliency and for System Protection are lower than the amounts approved by the Commission in Case No. U-21585. This lower amount is due to project selection for the test year in the instant case; the Company's identified projects in these two sub-programs, in total, require less funding than those included in Case No. U-21585.

Q. What metrics will the Company track in the IRM?

A. The Company plans to continue tracking the same metrics as those included in Case No. U-21389, plus an additional metric for Repetitive Outages, and report them to the Commission annually.

FIGURE 32
PROPOSED IRM METRICS

Sub-Program	Proposed Metric(s)
Lines Reliability - LVD	• Miles of Targeted Circuit Improvements • Fuse Locations • LVD poles replaced
Resiliency	• Fractionalization projects completed
System Protection	• Relays installed
Repetitive Outages - LVD	• Zones Improved
Vulnerable Communities	• Miles of Vulnerable Communities Resiliency Plan projects completed

Q. What dollar amounts, and number of projects, did the Company plan to perform during the first year of the IRM, covering the period from March 1, 2024 to February 28, 2025?

A. For the first year of the IRM, covering the period from March 1, 2024 to February 28, 2025, the Company planned to perform the number of projects with the associated dollar amounts listed in Figure 33.

FIGURE 33
YEAR 1 IRM: TARGETED METRICS AND APPORVED SPEND

Sub-Program	Performance Metrics	Target Units	Approved Spend
Lines Reliability	Miles of Targeted Circuit Improvements	50	$36,880,000
	Lateral fuses added	7,000	
	LVD poles replaced	300	
Resiliency	Fractionalization projects	4	$8,973,000
System Protection	Relay Panels Installed	16	$3,473,000
Total			**$49,326,000**

Q. What dollar amounts, and number of projects, did the Company actually perform during the first year of the IRM?

A. The actual performance in dollar amounts and number of projects are listed below in Figure 34.

FIGURE 34
YEAR 1 IRM: ACTUAL METRICS AND ACTUAL SPEND

Sub-Program	Performance Metrics	Actual Units	Actual Spend
Lines Reliability	Miles of Targeted Circuit Improvements	56	$52,817,000
	Lateral fuses added	8,524	
	LVD poles replaced	372	
Resiliency	Fractionalization Projects	1	$7,992,000
System Protection	Relay Panels Installed	17	$5,323,000
Total			**$66,132,000**

Q. Why did the Company not achieve the targeted spend in Resiliency?

A. The Company experienced a series of delays in beginning the fractionalization projects in the Resiliency sub-program, which ultimately hindered the ability to complete the entire approved spending amount in the 12 months of IRM year 1. The fractionalization projects in the Resiliency sub-program were delayed in securing easements and obtaining permits in a timely manner. While these permitting delays did move the completion date of these projects beyond the end of the first year of the IRM, all listed projects will be completed during the 2025 calendar year, during the second year of the IRM. Further details are provided as part of the Company's IRM reconciliation in Case No. U-21918.

Q. Did the Commission discuss any considerations for the IRM?

A. Yes. In its Order in Case No. U-21389, the Commission stated that it would review the IRM and

> "will consider, among other things, evidence presented on whether the investments are, in fact, being deployed equitably, whether the investments exacerbate or perpetuate racial or socioeconomic disparities in service, whether there has been a positive impact on reliability and resilience,

whether there is sufficient opportunity for scrutiny of the investments, and whether customers have benefitted from the IRM mechanism."

Q. How did the IRM positively impact reliability and resiliency?

A. The Company estimates the work completed drove improved performance as measured by SAIDI excluding MEDs of 3 minutes and All-weather SAIDI of 12 minutes while experiencing one less MED than in 2024.

Q. Did the Company deploy investments in an equitable manner?

A. Yes. The Company invested $6,315,000 of the total $66,132,000 spending, or 9.5%, in EJ communities. This IRM spending in EJ communities was greater than a proportional amount when considering the general make-up of the Company's service territory. EJ communities consist of approximately 4.1% to 9.2% of the Company's 1.9 million customers. The low-end customer count range of 4.1% represents the number of customers, approximately 78,000, living within the EJ-designated census tracts, while the high-end range of 9.2% represents the number of customers, approximately 175,000, served on the 2.5% of the Company's 61,621 low voltage primary distribution circuit miles that provide service to EJ communities.

Q. Are there any additional benefits to the IRM?

A. The IRM serves as a way ensure proactive spending on projects that are beneficial to deliver a reliable and resilient system. By ring-fencing capital, it will not be diverted to other purposes, and if not spent, customers receive the benefit of a refund. Because the Company did not achieve the entire approved spend in Resiliency, customers will benefit from the refund discussed in Case No. U-21918.

V. HISTORICAL SYSTEM PERFORMANCE

Q. How does the Company evaluate electric distribution system performance?

A. The Company considers several reliability metrics, with SAIDI being the most prominent. Other key reliability metrics measured and tracked by the Company include SAIFI, CAIDI, and CEMI. Historical performance for these metrics is detailed in this section of my testimony.

Q. Why does the Company focus on SAIDI as part of its electric distribution spending?

A. The importance of SAIDI performance was emphasized in a September 1, 2009 Report addressed to the Michigan State Legislature, submitted on behalf of the MPSC, in accordance with Section 10p of 2008 PA 286, MCL 460.10p, where it was stated:

> In light of the research Staff conducted, the Commission finds that Consumers Energy and Detroit Edison at this time should include SAIDI, SAIFI, and CAIDI reporting (with and without major events) on a rolling five year average in a new docket that will be opened by the Commission. These indices have been proven to show the reliability of electricity in a utility's power system and are useful to the Commission in identifying utility performance trends for each specific utility on a going forward basis. The intent of the information is not to benchmark the utilities nationwide or within the state, but rather to measure performance levels of each utility against its own historical data.

Additionally, in accordance with the September 15, 2009 Order in Case No. U-16066, and a subsequent order in the same docket on January 23, 2014, the Company provides the MPSC annual performance information related to SAIFI, CAIDI, and SAIDI with and without MEDs, on a rolling five-year average, using the industry standard IEEE method of calculation.

Q. What are the components of SAIDI?

A. SAIDI is comprised of two components: SAIFI and CAIDI.

- SAIFI is a measure of frequency of outages that is driven by system condition, system configuration, and system challenges (i.e., weather).

- CAIDI is a measure of the duration of interruptions, and is driven by system condition, the number of interruptions, resource availability, and restoration management practices.

SAIDI is calculated as follows:

SAIDI = SAIFI * CAIDI

Figure 35 shows Consumers Energy's SAIFI results over the period of 2015 through 2024, excluding MEDs.

FIGURE 35
SAIFI (2015-2024) EXCLUDING MEDS

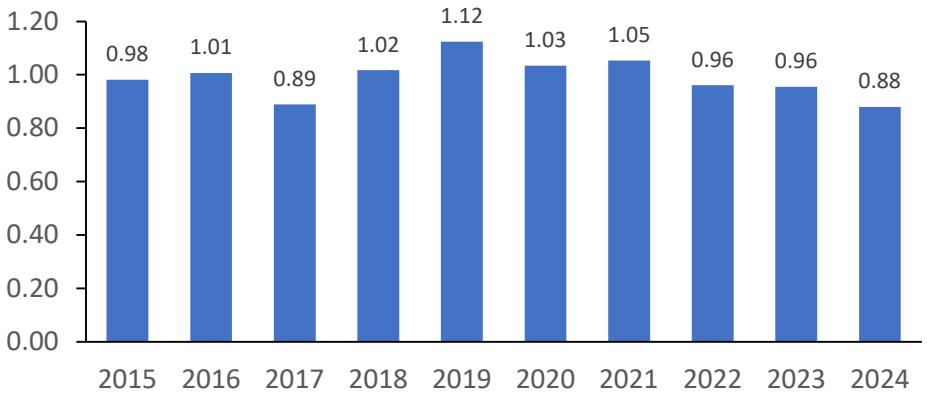
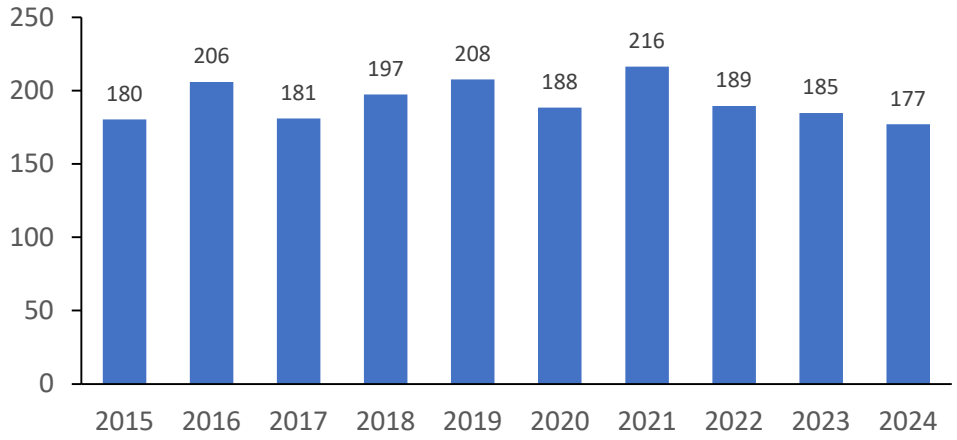


Figure 36 shows Consumers Energy's CAIDI results over the period of 2015 through 2024, excluding MEDs.

FIGURE 36
CAIDI (2015-2024) EXCLUDING MEDS

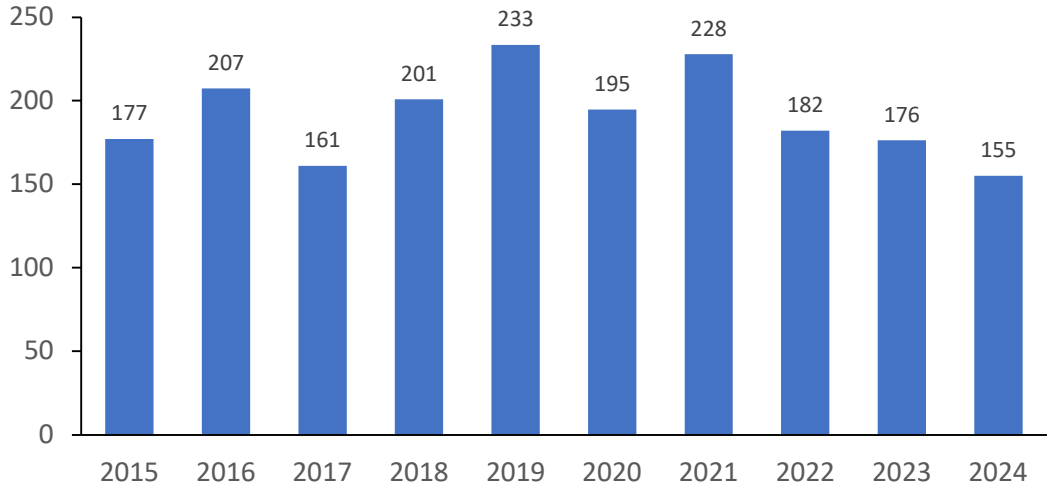


Q. What has been the recent reliability performance of Consumers Energy's distribution system?

A. Figure 37 below shows Consumers Energy's SAIDI results, excluding MEDs,[19] over the period of 2015 through 2024. MEDs are excluded from these totals to normalize performance data for unusually severe weather. The methodology for determining the level of storm activity to exclude in developing this chart is based on the IEEE *Guide for Electric Power Distribution Reliability Indices*.

[19] IEEE Standard 1366-2012 defines the methodology for calculating a MED. It is based on a statistical analysis of five sequential years of daily values. In 2021, Consumers Energy adopted a refined methodology that transitions from a calendar day evaluation period to a rolling 24-hour evaluation period. This methodology better captures MEDs that straddle consecutive calendar days.

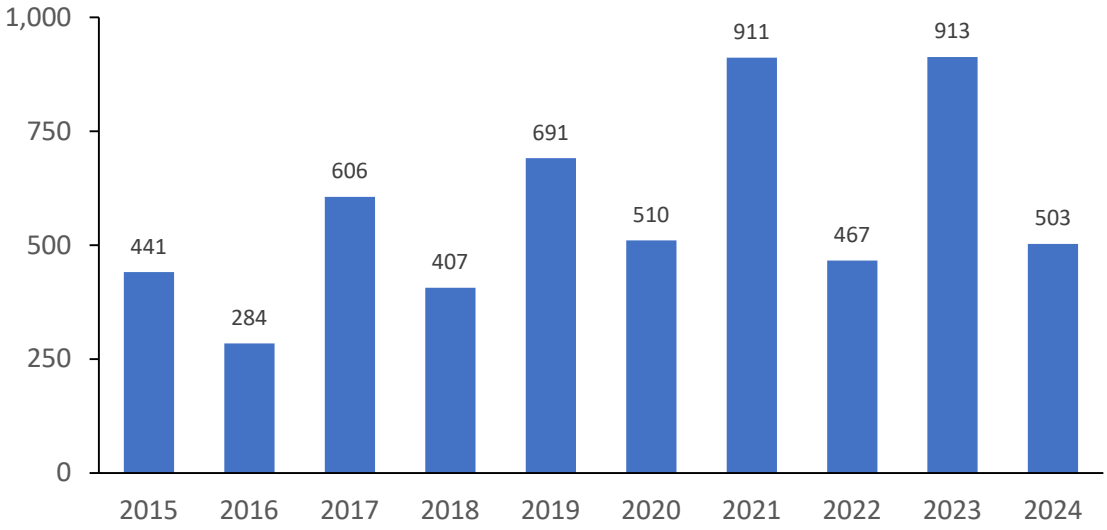
FIGURE 37
SAIDI (2015-2024) EXCLUDING MEDS



Q. If MEDs are *not* excluded, what has been the Company's recent SAIDI performance?

A. The Company's SAIDI results over the period of 2015 through 2024, *including* MEDs, are shown in Figure 38 below.

FIGURE 38
SAIDI (2015-2024) INCLUDING MEDS



Q. Please explain the year-over-year variation in SAIDI when MEDs are included.

A. The year-over-year variation is driven in part by the number of MEDs each year, as any MED is likely to result in more customer outages than on a normal day. The number of MEDs in each year from 2014 through 2023 is shown in Figure 39 below.

Storms in March 2017, July 2019, June 2020, August 2021, and February 2023 all exceeded this threshold, and all translated into large increases in customer interruption minutes, driving the higher annual SAIDI totals in those years. In most cases, these were multi-day storms that resulted in consecutive MEDs.

Compared to the middle part of the last decade, the number of MEDs has been consistently higher since 2017, an indicator of worsening weather and system deterioration.

FIGURE 39
MEDS PER YEAR, 2015-2024

Year	MED Days
2015	3
2016	5
2017	8
2018	7
2019	9
2020	8
2021	11
2022	9
2023	11
2024	10

Q. What is the Company's forecast for CEMI performance through 2028?

A. Absent the increased funding requested by Company witness Partlan for the Repetitive Outage Program that is needed to achieve the MPSC's Service Quality and Reporting Standards goal for CEMI-4, the Company would expect CEMI-4 performance as outlined in Figure 40 below.

FIGURE 40
CEMI-4 FORECAST 2025-2029

	2025	2026	2027	2028	2029
SAIFI (Including MEDs)	1.27	1.22	1.17	1.11	1.04
Percent of Customers at CEMI-4 or above	8.9%	8.2%	7.5%	6.7%	5.6%

FIGURE 41
CEMI-4 FORECAST 2025-2029 WITH INCREMENTAL FUNDING

	2025	2026	2027	2028	2029
Percent of Customers at CEMI-4 or above	8.9%	6.0%	6.0%	6.0%	5.0%

Q. How is the Company's recent SAIDI performance broken down by system component?

A. Figure 42 below provides a breakdown of SAIDI by LVD lines, HVD lines, LVD substations, HVD substations, and the transmission system ("ITC").

FIGURE 42
SAIDI BY SYSTEM COMPONENT 2020-2024

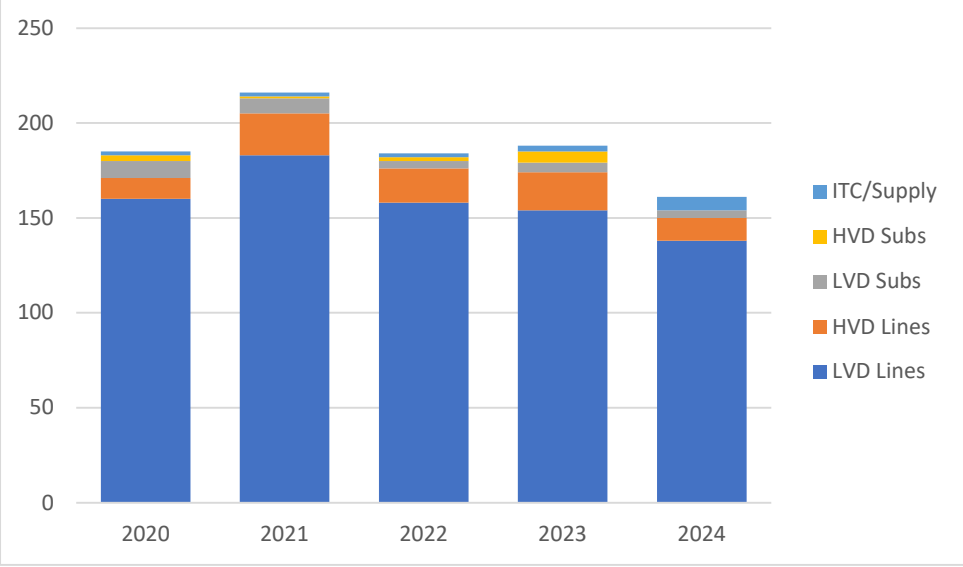


Figure 43 through Figure 45 below show the top causes of outages for HVD lines, LVD lines, and substations by illustrating the five-year average alongside the 2024 results for each cause category, with the five-year averages shown in descending order.

Green bars indicate that the 2024 results were better than the five-year average, while red bars indicate that they were worse.

FIGURE 43
HVD LINES SAIDI MINUTES BY OUTAGE TYPE

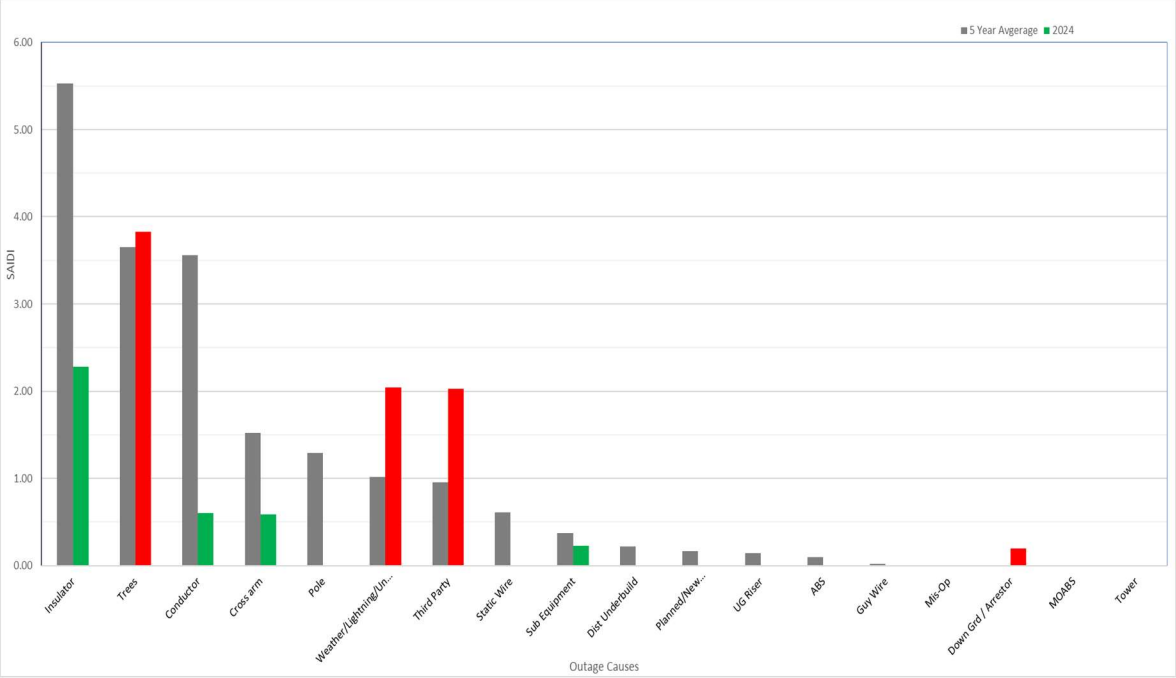


FIGURE 44
LVD LINES SAIDI CAUSES

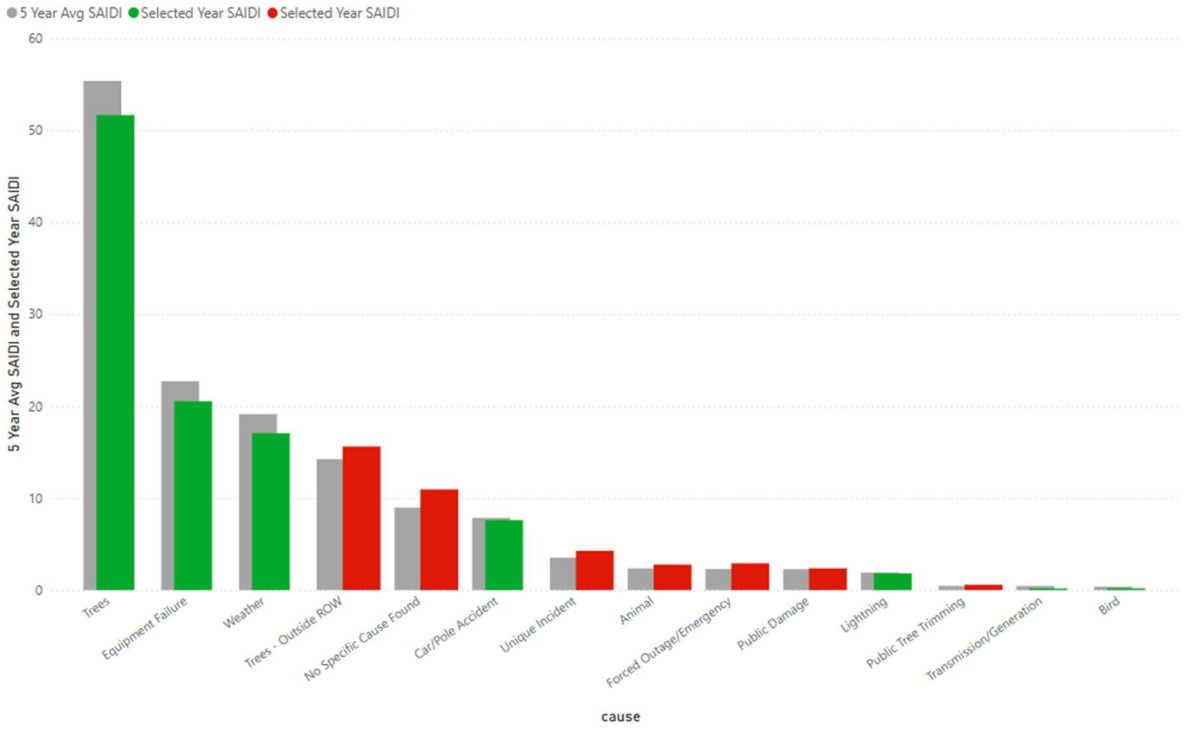
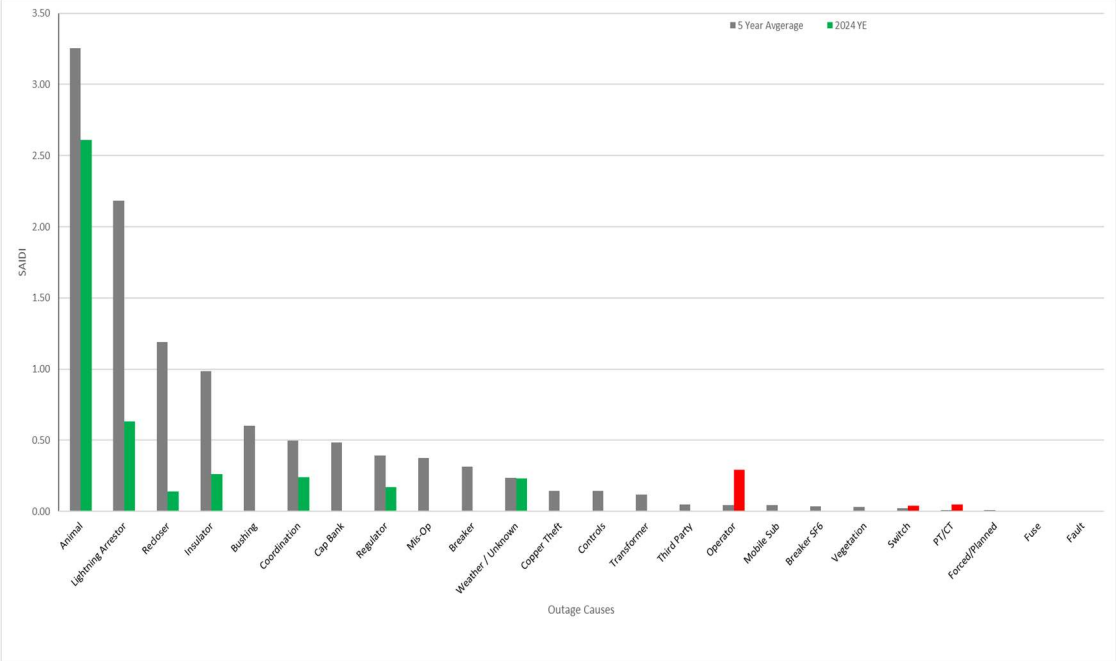


FIGURE 45
SUBSTATION SAIDI MINUTES BY OUTAGE TYPE



Q. Please describe the Company's recent experience with weather.

A. The Company monitors wind speed data from 21 different official National Weather Service stations in Michigan, as shown in Figure 46 below.

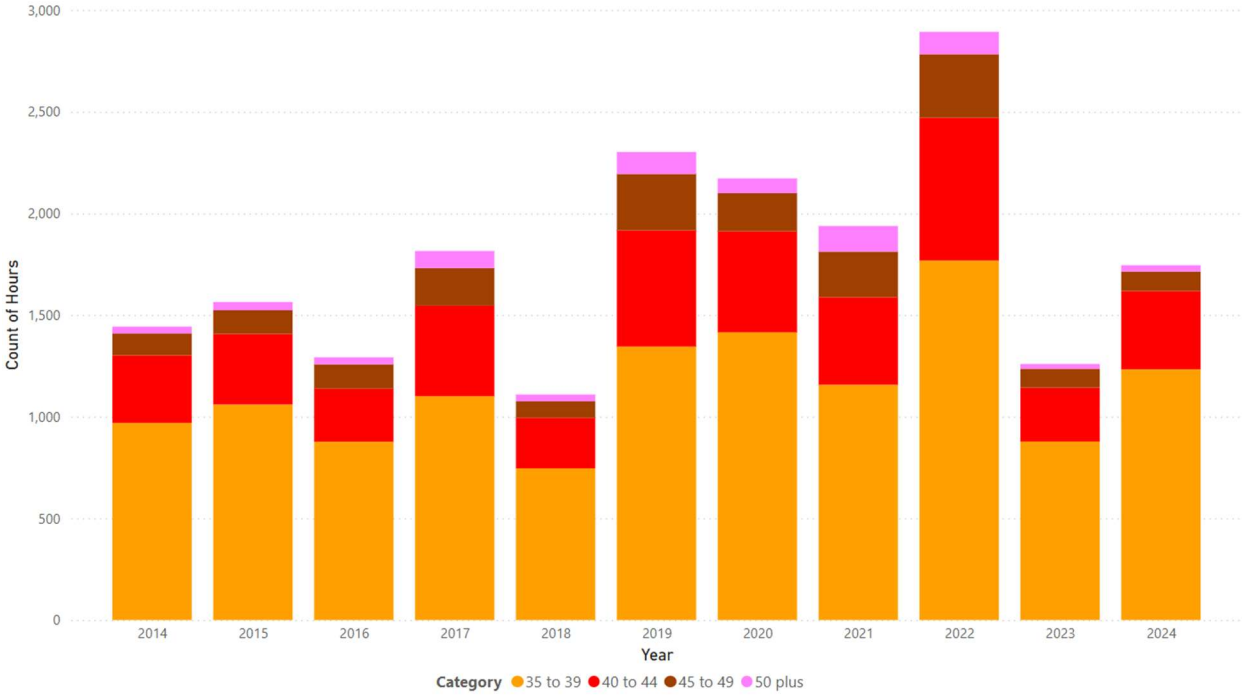
FIGURE 46
OFFICIAL NATIONAL WEATHER SERVICE WIND OBSERVATION STATIONS



In recent years, the Company has observed that wind speeds across the system have increased in severity.

Figure 47 below illustrates the number of hours, aggregated across these 21 observation stations, during which wind speed was sustained at higher than 35 mph. Sustained wind observations have generally been increasing over the past decade.

FIGURE 47
STATION HOURS EXCEEDING HIGH WIND SPEED THRESHOLDS



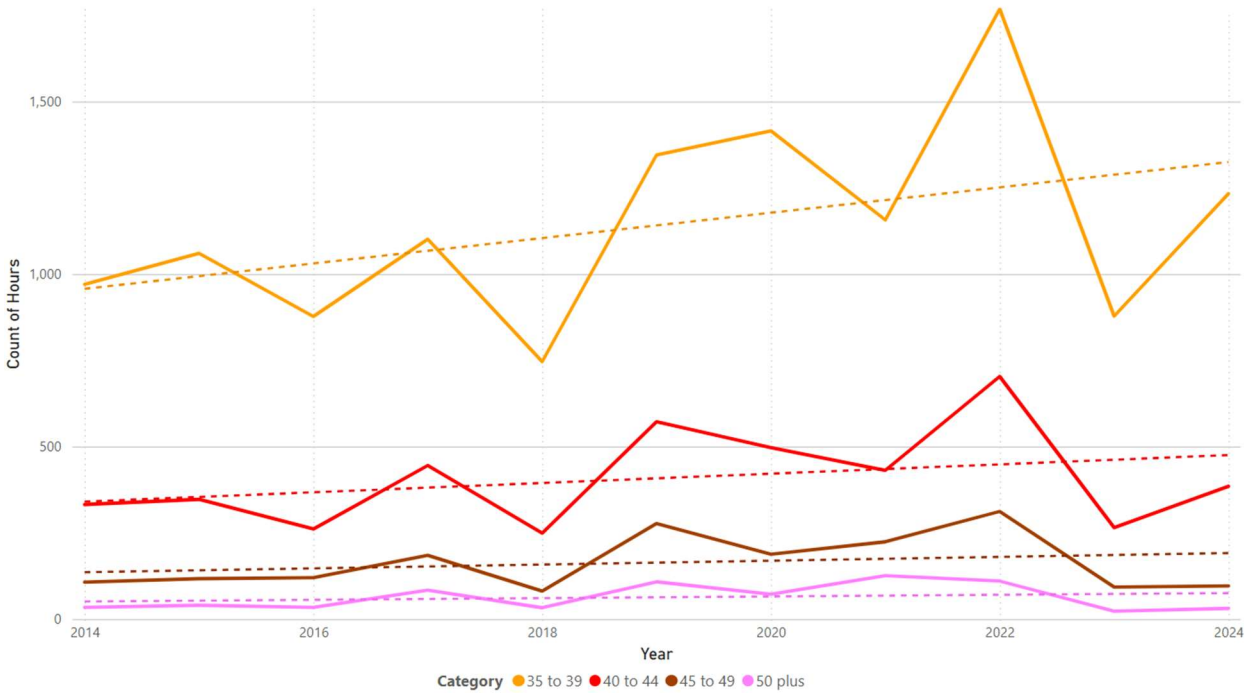
In terms of wind-caused outages, wind gusts can be even more damaging than sustained high winds, given the often-violent nature of gusts.

The National Weather Service observation stations record gusts when there are rapid fluctuations of 10 knots (11.5 mph) or more between peaks and lulls over a 10-minute window, with the gust speed being the maximum wind speed observed in that window.

Figure 48 below illustrates the number of hours, aggregated across the 21 stations, during which gusts of more than 35 miles per hour were observed, isolating the frequency of gusts exceeding 35 miles per hour in 5 mph bands.

As illustrated by the trend lines, gusts have been becoming more frequent at each of the high-speed bands.

FIGURE 48
STATION HOURS EXCEEDING HIGH GUST THRESHOLDS, 2014-2024



The data shown in Figure 47 and Figure 48 illustrates that wind speeds and gusts have been getting increasingly worse in recent years.

Q. What conclusions does the Company draw based on this wind speed data?

A. This data highlights that, as Michigan sees increasingly extreme weather, the electric distribution system needs to be hardened against that weather to improve resiliency. It is also important to note that wind gust data does not capture the full picture of severe weather; while 2023 was less gusty than other recent years, it did feature a major ice storm and several tornadoes that drove SAIDI.

VI. TECHNOLOGY PROJECTS SUPPORTING ELECTRIC DISTRIBUTION

Q. Is the Company planning technology projects in the test year that support the Company's electric distribution strategy?

A. Yes. Company witness Stacy H. Baker is sponsoring:

a) the Electric GIS Utility Network Transformation project; and

b) the Electric GIS Design Platform Modernization project.

Q. Please explain the Electric GIS Utility Network Transformation project.

A. This project will transform the Company's current GIS platform to the Environmental Systems Research Institute ("ESRI") Utility Network Model and establish a unified HVD, LVD, and substations data model. This transformation aims to optimize core engineering and operational processes, technologies, and data.

The Company's GIS for electric records is expanding as an authoritative source for asset connectivity, location, and health information. However, growing business requirements for advanced analytics and regulatory mandates necessitate more granular geospatial insights. Existing functionality does not meet business partner needs, and GIS data is refreshed in batch mode once a day, leading to mismatches with real-time systems. Managing HVD and LVD data in different models remains challenging.

The Company's past implementation of ESRI's GIS for Electric, version 10.8.1, will be unsupported after March 1, 2028. Critical third-party solutions supporting key editing and business functionality are also ending support without upgrade options, posing risks for security updates. ESRI's development focus is shifting to the ArcGIS Utility Network Management extension, ArcGIS Enterprise, and ArcGIS Pro. The vendor's development team has reached the limits of ArcMap and the geometric network's capabilities and will no longer build additional functionality. Future development and

enhancements are focused on the next-generation technologies of the Utility Network and ArcGIS Pro. ESRI utility solution partners are also moving their product lines away from the geometric network, soon supporting only the Utility Network.

The project scope includes:

1. Upgrading all database, web, and application servers to supported Windows version;
2. Upgrading end user application from ArcGIS Desktop to ArcGIS Pro;
3. Migrating and converting LVD and HVD GIS data from geometric network data schema to the Utility Network, iteratively publishing data to new model for consumption;
4. Reconfiguring electric applications that are integrated with GIS or that consume GIS data; and
5. Creating a substation asset model.

Q. What benefits will this project provide?

A. This project creates value for the Company by:

1. Mitigating risks associated with product support end of life;
2. Enabling detailed asset management and location-based analytics to bring clearer understandings around the assets that support energy delivery;
3. Increasing productivity through use of shortcuts, templates, and streamlined workflows within the software;
4. Providing extensive, out-of-the-box tracing tool;
5. Providing 3D visualization functionality;
6. Enabling users with editing tools, giving them guidance at every step of the process for developing workflows and enforcing stronger data integrity;
7. Viewing the up-to-date network in a map or schematic diagram and be able to quickly toggle back and forth between them; and
8. Enabling archiving and historical versioning to view the state of the electric network over time.

All these capabilities will result in greater insight and efficiency that improve the safety and delivery to customers. The Utility Network enables implementation of

third-party tools that will allow us to keep the operational model more up to date as circuits with temp conditions and/or control tags can be imported as needed.

Q. What alternatives did the Company consider?

A. Alternatives considered included:

1. Continue to use geometric network. This alternative was not selected because the architecture is at the end of its life. Additionally, dependent third-party solutions are moving away from the geometric network, making it unsustainable for continued use.
2. Moving to Utility Network and migrating to a supported platform. This alternative was chosen to enable the Company to leverage a cloud-based solution and provide options for using third-party solutions.

Q. What is the cost of this project?

A. The Electric GIS Utility Network Transformation project requires $1,324,225 in capital ($1,059,380 ROM adjusted capital) and $519,952 in O&M in the test year.

Q. How did the Company develop its projected expenditures for the Electric GIS Utility Network Transformation project?

A. The projected expenditures were estimated based upon previous work for that product family and anticipated software costs.

Q. Please explain the Electric GIS Design Platform Modernization project.

A. This project is replacing the existing design software for LVD with a new solution that will be fully integrated into the ESRI R GIS platform already in use by the Company.

This new solution will leverage GIS asset data to generate engineering designs. It will allow engineering teams to have a single source and format to view asset data, construction drawings, and redlines in both the back office and the field.

This change will further enable improvements to the mobile platform in quality of data used by the closeout team. This will also reduce the back-end posting effort by using

the native GIS data format, thereby improving data quality by reducing re-keying of data. The current design software creates waste in three areas for many teams, including LVD Engineering, Field Leaders, and Customer Energy Management ("CEM") Service Designers.

First, the current software does not support the native GIS data format, and will not support future enabling work management needs. This causes waste and room for error by having to re-draw designs in GIS already created, and prevents optimization of the work process.

Second, it is not able to integrate with SAP to automatically order materials based on the design.

Third, the current software lacks needed mobile functionality due to its lack of support for the native GIS format. The designs are not geo-referenced to the exact location and cannot fully use redlining capability, which causes a significant impact to data quality and crew performance.

The project scope includes:

1. Installing a new solution that will integrate to GIS;
2. Using GIS geospatial and asset information data and the GIS platform for generating Electric LVD engineering designs;
3. Integrating to and from SAP to automate Compatible and Mass Unit material ordering capability;
4. Installing new and upgrading existing geospatial platform infrastructure to support additional users (Electric LVD designers, Field Leaders, Planners, Schedulers, etc.) of GIS;
5. Integrating to ProjectWise (engineering content management system);
6. Configuring mobile toolset;
7. Re-engineering the existing GIS data model to handle asset life cycle; and

8. Configuration for new ArcGIS services.

Q. What benefits will this project provide?

A. This project creates value for the Company by:

1. Eliminating the need to duplicate all design work so it is in both the design system and GIS;
2. Enabling mobile editing and redlining on the design in GIS;
3. Enabling integration with SAP; and
4. Using the capabilities of the next generation GIS platform to be delivered through an in-progress business case.

Q. What alternatives did the Company consider?

A. Alternatives considered include:

1. Enhance existing software to be able to connect to GIS and SAP. This option was not selected because it is not native functionality in the current software. This would be extremely expensive to develop and implement.
2. Continue with current solution. This option was not selected as the current software and data format hinders all downstream work and asset management workflows. This adds additional effort, technologies, and costs.
3. Implement a GIS based solution. This alternative was selected because a new solution will use existing geospatial platform on premise, and will move the Company to a single data format that will enable both field and back office employees.

Q. What is the cost of this project?

A. The cost of the Electric GIS Design Platform Modernization project is $1,476,532 in capital expenditures ($1,181,225 Rough Order of Magnitude adjusted capital) and $136,794 in O&M in the test year.

Q. How did the Company develop its projected expenditures for the Electric GIS Design Platform Modernization project?

A. The projected expenditures were estimated based upon previous work for this product family and anticipated software costs.

VII. ELECTRIC DISTRIBUTION O&M EXPENSES

Q. What is included in the Company's distribution O&M spending?

A. The Company's O&M spending supports its capital investments through maintenance and operation of grid infrastructure, plus engineering and design work required to execute projects, and provides for restoration of service to customers following interruptions. Forestry Line Clearing O&M is discussed by Company witness Stewart, and Service Restoration O&M is discussed by Company witness Snider.

The Company's distribution O&M spending includes: (1) funding for the Company's ongoing distribution Operations and Engineering functions; and (2) funding for certain internal organizations, such as training and equipment repair, that support both functions.

Summaries of the distribution O&M expenses are provided in Exhibits A-122 (MPK-12) and A-123 (MPK-13), and a five-year average of O&M expenses is provided as Exhibit A-124 (MPK-14).

Q. What is the overall recent trend in the Company's distribution O&M?

A. In 2024, the Company's distribution O&M was $246,620,000, as shown in Exhibit A-124 (MPK-14), line 55, column (f). For the years 2020 through 2024, actual O&M expenses were taken from Consumers Energy's internal reporting records. The Company's projected test year distribution O&M is $301,852,000, as shown in Exhibit A-124 (MPK-14), line 55, column (l). This test year projection is based on the sum of each individual O&M line item, which I will discuss in the subsequent sections of my direct testimony.

Q. Do test year projected O&M expenses represent continuing functions and activities?

A. Yes. The Company projects that the functions and activities represented by the expenses for the test year will be similar and consistent with the functions and activities that were performed in 2024, with any exceptions explained below.

Q. Please explain Exhibit A-128 (MPK-18).

A. Exhibit A-128 (MPK-18) presents the amounts of the projected O&M expenses in my other O&M exhibits, and identifies an inflation component that reflects how much inflation affected O&M spending levels between the 2024 historical year and the test year in this case.

In this exhibit, column (b) shows the historical O&M expense. Column (c) shows the historical amount an inflation rate or merit increase rate was applied to. Column (g) shows the amounts to which an inflation rate or merit increase rate was applied for the year ending December 31, 2025. Columns (d), (f), and (h) show the merit and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i). Column (j) is aligned with the Company's projected expenses for each sub-program for the test year, as shown in Exhibits A-125 (MPK-15) and A-126 (MPK-16).

However, the Company's Electric Distribution O&M has generally not been developed by simply taking 2024 actuals and then applying inflation rates to them. Each O&M sub-program's projected expenses are developed using methodologies specific to the sub-program, which I will discuss throughout this O&M section of my testimony.

The purpose of Exhibit A-128 (MPK-18) is simply to identify an inflation rate and an inflation component so that intervenors who wish to consider alternative inflation rates can make comparisons.

Q. Is it possible to calculate unit costs for any O&M sub-programs?

A. Not in a consistent way. Some O&M sub-programs are largely based on headcount, where the expenses will be heavily based on the number of employees. Others are based largely on projected work volumes. However, many O&M expenses correspond to fixed costs that do not vary with any kind of unit. Many O&M sub-programs involve some kind of blend of inputs, being based on some combination of headcount, work volume, and fixed or one-time costs.

VIII. ELECTRIC OPERATIONS

Q. Please detail the O&M programs which comprise Electric Operations.

A. As shown in Exhibit A-125 (MPK-15), Electric Operations includes the following programs:

- O&M Associated with Construction;
- Non-Forestry Reliability (Forestry-related Reliability is discussed in Company witness Stewart's testimony);
- Operations, Maintenance, and Metering;
- Service Restoration;
- Field Operations;
- Compliance and Controls;
- Planning and Scheduling;
- Work Management and Customer Delivery;
- Operations Management; and

- Operations IT Projects.

A. O&M Associated with Construction

Q. Please describe expenses associated with the O&M Associated with Construction Program.

A. In historical years, the Company incurred O&M expenses to purchase transformers, regulators, auto boosters, and isolators for use across the electric distribution system, with these expenses offset to various degrees by credits accounted for at purchase, and subsequently allocated back to this O&M program when the equipment was installed or retired. The Company is not projecting any expenses in the O&M associated with the Construction Program in the bridge period or test year.

B. Non-Forestry Reliability

Q. Please describe the O&M expenses related to the Non-Forestry Reliability Program.

A. The Company's Non-Forestry Reliability O&M Program focuses on inspecting and monitoring system equipment. The Non-Forestry Reliability Program consists of four sub-programs:

- LVD Lines Reliability;
- HVD Lines Reliability;
- LVD Substations Reliability; and
- HVD Substations Reliability.

LVD Lines Reliability

Q. What work activities are carried out in the LVD Lines Reliability O&M sub-program?

A. The LVD Lines Reliability O&M sub-program supplements the LVD Lines Reliability capital sub-program through inspection and maintenance of LVD lines and LVD Metro

assets. As illustrated in the Reliability Roadmap, IEEE recommends a certain cadence for inspecting different components of the LVD system, and repairing any issues that are identified. This includes general pole and line inspections, padmount inspections, and inspections of devices and equipment like reclosers, switches, and capacitors.

Q. Please describe general LVD line and pole inspections.

A. General LVD line inspections are conducted as discussed in the testimony of Company witness Partlan. Issues identified in those inspections that are not capital replacements are corrected through this O&M program; issues that do require capital replacements are generally addressed in the LVD Lines Demand Failures sub-program. Some examples of this O&M work include:

- Replacing a fuse link to put a fuse back into service or correct system protection issues, including device reach and coordination between devices;
- Moving a jumper on a line or device to balance load among phases or reconfigure the customer's service;
- Bringing assets up to existing standards, such as by moving lightning arrestors to the load side of the transformer cutout;
- Replacing damaged/stolen components, such as sections of copper down grounds that have been stolen or broken crossarm braces;
- Adding or correcting existing labels for devices in the field to match Company records; and
- Adding animal mitigation due to past animal related outages.

This also includes groundline pole inspections to identify individual LVD poles that need to be replaced. Groundline pole inspections are discussed in more detail in Company witness Partlan's testimony.

Q. What is included in padmount inspections?

A. The exterior of padmounted equipment (including the base) is visually inspected each year for any signs of leaking oil, holes that expose electrical components, missing transformer locks, or missing labels. If found, the holes are patched, and labels are replaced. If equipment is unrepairable, replacement of equipment is done under the LVD Lines Demand Failures sub-program as described in the testimony of Company witness Partlan.

Q. What work is done on devices and equipment?

A. Maintenance of devices and equipment is required to maintain the benefits of these devices and equipment. The Company can remotely monitor equipment equipped with a modem to identify when it is not functioning properly. When this occurs, the device or equipment is investigated to determine the cause. If the equipment or device is unrepairable, replacement of equipment is done under the LVD Lines Demand Failures capital sub-program.

Equipment without a modem needs to be inspected on a cycle to ensure it is functioning properly. This equipment includes a portion of electronic reclosers, and all Gang Operated disconnect switches. Electronic reclosers without a modem need the control unit checked for error codes. If an error is found, the recloser is investigated to determine the cause. If the recloser is unrepairable, replacement of recloser is done under the LVD Lines Demand Failures capital sub-program.

All electronic reclosers require battery replacement to ensure the battery is working correctly and the electronic controls of the recloser operate as intended. Batteries should be replaced on a four-year cycle.

Gang Operated disconnect switches need to be inspected for damage or erosion and cycled to ensure they work properly when needed for load transfers or isolation of damage. If damage or erosion is found or the switch does not cycle correctly, it can be repaired or replaced, depending on the issue.

Q. How does this work benefit customers?

A. This work benefits customers by reducing outages caused by failed equipment, improving public safety, improving power quality, getting the full life out of installed equipment, and reducing electric load.

LVD line and pole inspections proactively identify failed equipment, providing a reliability benefit to customers by improving the condition of system equipment when failed components are replaced and placing the system back into a normal operating condition, eliminating an outage in the future. It is estimated the average order saves 50,000 customer-outage-minutes.

Padmount inspections provide a public and environmental safety benefit. The Company reduces the risk of the public coming in contact with energized equipment by fixing holes and replacing locks. Identifying oil leaks ensures a minimal amount of transformer oil is released to the environment and timely correction of leaks.

Maintenance of devices and equipment ensures the devices operate as intended and are available for use when needed. It also allows the Company to get the benefits from the full life of the equipment.

When electronic reclosers have errors, they may not operate as intended. This could mean causing outages to customers when no sustained fault is present or causing the upstream device to open instead, causing more customers to be impacted by an outage. On

average, electronic reclosers on the LVD lines feed 670 customers, which means they have a large impact on customers. Timely battery replacements ensure the electronic reclosers have power and can be operated by line crews, improving restoration time.

Capacitor banks help to improve power quality for customers and reduce losses on the electric system by improving the power factor of the electric system. They are one of the components of the Company's CVR project, as discussed in Company witness Partlan's direct testimony. Keeping capacitor banks operational is integral to the success of the CVR program.

Gang Operated Switches are used to isolate damage and transfer load from a circuit over to the adjacent circuit. They are regularly used in both planned and emergent events where equipment or lines need to be taken out of service. They are used to keep as many customers restored as possible during planned work, and to more quickly restore customers during emergent events.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 4, column (l), the Company is projecting to spend $8,000,000 in the test year.

Q. How was this spending amount determined?

A. This spending amount is based on the Company's costs to complete the inspection and maintenance work described above. In particular, the Company is projecting to spend $3,500,000 in the test year on maintaining disconnect switches, $2,200,000 on the groundline pole inspection program, and $500,000 on padmount inspections. The remaining $1,800,000 will be spent on the other LVD inspections defined in the Reliability Roadmap.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. Historic spending levels in this sub-program were insufficient to complete all of the IEEE-recommended work. The Company identified this issue when developing the Reliability Roadmap in 2023, and began developing a plan to increase needed maintenance work going forward. Additionally, the groundline LVD pole inspection program is essential for the Company to be able to replace deteriorated LVD poles on its system.

HVD Lines Reliability

Q. What work activities are carried out in the HVD Lines Reliability O&M sub-program?

A. The Company's HVD Lines Reliability O&M sub-program includes the expense portion of the Company's HVD pole inspections, which occur on a 12-year cycle; and annual Motor Operated Air Break Switches ("MOABS") tests. Each of these is fundamental for maintaining HVD line assets. MOABS are a key component of SCADA on the HVD system, and are tested annually to ensure the controls are in proper working order. Also, the batteries are replaced every three to four years or sooner, as needed. The 12-year pole inspection cycle is discussed in the direct testimony of Company witness Hayward. The inspection data and information gathered through this O&M sub-program is key information used to assist in identifying line capital projects.

Q. How does this work benefit customers?

A. Both pole inspections and MOABS testing identify assets (poles and switches) for repair or replacement. These repairs and replacements *significantly* reduce the number of outages that would occur if this work were not performed (in the case of pole replacements) or greatly reduce the impact of outages when they do occur (in the case of MOABS).

Company witness Hayward details the benefits of HVD Lines Reliability investments supported by these inspections in her direct testimony.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 5, column (l), the Company is projecting to spend $891,000 in the test year.

Q. How was this spending amount determined?

A. This spending amount is based on the projected amount of work expected in this sub-program, specifically HVD pole inspections, testing of MOABS, and MOABS battery replacements.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is being driven by increased inspections and testing to support projected investment increases in the HVD Lines Reliability capital program.

Substations Reliability – LVD and HVD

Q. Please describe the general work associated with both the LVD and HVD Substations Reliability sub-programs.

A. These two sub-programs provide proactive inspections and maintenance to equipment to maintain operational functionality of LVD and HVD substation assets, as well as the Company's Metro assets.

While *proactive* work is done in the LVD and HVD Substations Reliability O&M sub-programs, *reactive* work to fix assets already broken is performed by this same workforce in the LVD and HVD Substations Demand O&M sub-programs described later in my direct testimony. Though there are separate line items for LVD and HVD substations,

the same Company workforce addresses both asset groups using a common plan - in short, a single substation operations workforce performs work in four different O&M sub-programs.

As discussed in the Reliability Roadmap, the Company is increasing its total substation O&M spending across the four sub-programs to better align with the *Electric Substation Reliability Guidelines* ("ESR-1"). Historical levels of funding have not been adequate to complete sufficient inspections or to address maintenance backlogs.

Substation inspections are particularly important because they allow the Company to monitor the health of transformers, load tap changers, oil circuit breakers, and other critical substation equipment. If equipment is not monitored, the risk of failure increases, and these kinds of substation equipment failures can result in lengthy and widespread outages lasting until repairs can be made.

Additionally, ongoing substation maintenance provides these benefits:

- Increased reliability and resiliency by avoiding outages due to equipment failure or mis-operation;
- Decreased costs by avoiding emergency repairs, allowing for more predictability in the capital workplan; and
- Extension of asset life, avoiding emergent capital replacements and allowing for more predictable future capital investments.

Q. Please describe the work in the LVD Substations Reliability O&M sub-program as shown in Exhibit A-125 (MPK-15), line 6.

A. The LVD Substations Reliability O&M sub-program supports substation and substation equipment inspections, recloser and circuit breaker test operating, and substation battery maintenance. This O&M sub-program also supports Metro system inspections. This sub-program includes required environmental inspections under the Spill Prevention,

Control and Countermeasure ("SPCC") Program. These equipment inspections are based on manufacturers' recommendations, industry best practices, and years of experience with the equipment in question, and include maintenance activities such as lubrication and changing of filters. Neglecting these inspections can result in premature equipment failure and additional capital expense.

Funding for 80% of the total HVD and LVD substation mowing and weed spraying expenses is included in this sub-program, and consists of typically one weed spray per year (a second weed spray was performed in 2021 due to unusually vigorous weed growth statewide) and a five-month (May through September) mowing program with a two-times-a-month mow interval.

Issues identified by inspections or patrols under this program are corrected through work orders in the LVD Substations Demand O&M sub-program, the LVD Substation Reliability capital sub-program, or the LVD Substation Demand Failures capital sub-program. Increased spending in this program will increase the number of substation equipment inspections that can be performed.

Q. Please describe the benefits to customers provided by the LVD Substations Reliability sub-program.

A. The LVD Substations Reliability sub-program includes inspections and maintenance that help avoid LVD substation outages. Bi-monthly patrol inspections of LVD substations identify issues that cannot be found through other means. In recent years, such inspections identified items such as copper theft from the substation, cracked and broken insulators, a burned up recloser control, and a broken pole—all of which could affect system operation and potentially result in outages.

On average, the total SAIDI minutes due to LVD Substation outages is 6.35 minutes. The average LVD substation outage resulted in 0.30 SAIDI minutes (the equivalent of 3,110 customers out of service for 180 minutes). In 2024, the most significant outage in duration was on the Easton substation. This single event resulted in 0.59 minutes of SAIDI (3,187 customers interrupted for 346 minutes). Company witness Hayward's direct testimony also provides details on a high-impact outage at the Verona substation in 2024.

Consequently, each outage avoided has a significant benefit to system reliability. Deteriorated or damaged electrical equipment can be prone to dangers such as electrical arcing and/or explosions, resulting in danger to customers and Company employees.

Maintaining equipment allows the system to be operated as intended at its most efficient level, and reduces the need for capital costs to rehabilitate or replace substations as well as decrease the frequency and duration of outages.

Q. Please describe the projected O&M expenses related to the LVD Substations Reliability sub-program, as shown in Exhibit A-125 (MPK-15), line 6.

A. The Company is projecting LVD Substations Reliability O&M expenses of $5,475,000 in the test year.

Q. Why is projected spending increasing relative to recent historical actuals for LVD Substations Reliability O&M?

A. As noted above, historical funding levels in this sub-program have not been sufficient to actually complete substation inspections on the appropriate schedule as given in the ESR-1 guidelines, compelling the Company to defer needed work. The Company is increasing the O&M spending in the substation O&M programs to get onto the nominal cycles

provided in the ESR-1 guidelines and clear maintenance backlogs. The projected spending level in the instant case will accomplish this.

Q. Please describe the work related to the O&M expenses for the HVD Substations Reliability sub-program as shown in Exhibit A-125 (MPK-15), line 7.

A. The goal of the Company's HVD Substations Reliability O&M sub-program is to maintain the safety and reliability of HVD substations.

This program includes several activities, such as monthly substation and substation equipment inspections, breaker test operating, and substation battery maintenance. This program includes required environmental inspections due to the SPCC Program.

Additionally, funding for 20% of the total HVD and LVD substation mowing and weed spraying expenses are included in this sub-program. Issues identified by inspections or patrols under this program are corrected using orders created under the Substation Demand—HVD O&M Program, HVD Substation Reliability Program, or HVD Lines and Subs Failures Program.

Q. Please describe the O&M expenses related to the HVD Substations Reliability sub-program, as shown in Exhibit A-125 (MPK-15), line 7.

A. The Company is projecting HVD Substations Reliability O&M expenses of $2,349,000 in the test year.

Q. Why is projected spending increasing relative to recent historical actuals for HVD Substations Reliability O&M?

A. As with LVD Substations Reliability O&M, historical funding levels in this sub-program have not been sufficient to actually complete substation inspections and maintenance on the appropriate schedule as given in the ESR-1 guidelines, compelling the Company to

defer needed work. The Company is increasing the O&M spending in all four substation O&M programs relative to historical averages to get onto the nominal cycles provided in the ESR-1 guidelines and clear maintenance backlogs. The projected spending level in the instant case will accomplish this. Note that in the case of HVD Substations Reliability O&M, projected test year costs are higher than the recent average but are in line with levels from 2024.

Q. Please describe the benefits to customers provided by the HVD Substations Reliability sub-program.

A. The HVD Substations Reliability sub-program includes inspections and maintenance that are expected to avoid HVD substation outages. On average, the total SAIDI due to HVD substation outages is 2.39 minutes. The average HVD substation outage resulted in 0.30 SAIDI minutes (the equivalent of 3,110 customers experiencing a 180-minute outage) but can be much larger in scope when they occur (such as the outage at Morrow Substation in January 2019 resulting in 2.686 SAIDI minutes). Consequently, each outage avoided has a significant benefit to system reliability. Additionally, there are public and Company safety benefits from having periodic inspections of HVD substations as electrical equipment that is deteriorated or damaged can be prone to dangers such as electrical arcing and/or explosions.

Lastly, maintaining equipment allows the system to be operated as intended and at its most efficient level, which keeps costs down and can decrease the frequency and duration of outages.

C. Operations, Maintenance, and Metering

Q. Please describe the work related to the Operations, Maintenance, and Metering Program (w/out Service Restoration), as shown in Exhibit A-125 (MPK-15), line 21.

A. The Company's Operations, Maintenance, and Metering O&M expenses consist of three demand sub-programs and the associated Electric Equipment Repair Center located in Alma. Additionally, the expense for Dissolved Gas Analysis testing of LVD and HVD substation equipment is included in this sub-program.

The Company's LVD Operations, Meter Services, and Meter Readings O&M spending includes several demand programs related to front-line operations of the distribution grid.

Q. What are the sub-programs contained within the Electric Operations, Maintenance, and Metering O&M expense program?

A. The sub-programs, as shown in Exhibit A-125 (MPK-15), lines 9 through 21, are:

- HVD Lines Demand;
- LVD Substations Demand;
- HVD Substations Demand;
- Corrective Maintenance;
- Staking;
- Meter Services;
- Meter Credits;
- Streetlighting;
- Service Calls;
- Alma Equipment Repair;

- Meter Reading;
- Meter Tech & Management System Support; and
- Smart Energy Meter Technology Center ("MTC")-Electric.

HVD Lines Demand

Q. What work activities are carried out in the HVD Lines Demand O&M sub-program?

A. The Company's HVD Lines Demand O&M sub-program includes certain expenses for repairs to 46 kV and 138 kV lines equipment. Specifically, these expenses address non-capital HVD failures identified in routine inspections or emergent customer-impacting events. For example, if a tree falls on a line and breaks it, a crew will fix the line, and this work is not capitalized. The HVD system is the backbone of the electric distribution system, and the work in this sub-program mitigates large and long outages that would otherwise come when these assets fail.

This sub-program also includes associated on-call costs for line crews. The Company has five or six crews on call at any given time to ensure they can be quickly deployed following outages. When large storm events are predicted, the Company may obtain additional or enhanced on-call crews. Activities in this program are typically emergent and identified by failures resulting in customer outages, failures resulting in equipment outages, key calls, helicopter patrols, ground patrols, and investigation of trip and reclose occurrences.

Q. How does this work benefit customers?

A. This sub-program supports preventative maintenance with repairs and upgrades of non-capital assets, downed wires, as well as splice and connector replacements. These repairs are completed to prevent outages and improve system integrity and reliability. In particular, the Company's 46 kV system is approximately 37% radial. On radial lines,

outages that require repairs before restoring customers contribute about 0.5 SAIDI minutes. If the Company is able to restore power before completing the repair, SAIDI contribution is about 0.1 minutes.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 9, column (l), the Company is projecting to spend $2,979,000 in the test year.

Q. How was this spending amount determined?

A. This spending amount was determined based on the projected number of HVD lines work orders that the Company will have to complete in the test year.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The Company has been making increasing use of technology, particularly infrared cameras, to identify anomalies on the HVD system, meaning more anomalies are being found. This has created a backlog, and the Company is increasing its spending in HVD Lines Demand O&M to address the backlog and continue fixing anomalies that are found.

Substations Demand—LVD and HVD

Q. Please describe the general work associated with both the LVD and HVD Substations Demand sub-programs.

A. These two sub-programs respond to failures resulting in customer outages or equipment outages, poor testing results (e.g., infrared inspections, oil sampling, etc.), and substation asset management database algorithms, supporting the Company's safety and reliability objectives by ensuring customer and electric system safety, outage restoration, and repairs to equipment to maintain operational functionality of LVD and HVD substation assets.

As noted earlier in my direct testimony, these two sub-programs employ the same Company workforce and overall workplan, along with the LVD and HVD Substations Reliability O&M sub-programs, and the Company is projecting increased spending in these sub-programs to ensure the Company can complete the necessary substation maintenance under the ESR-1 guidelines, as given in the Reliability Roadmap.

Q. Please describe the work related to the LVD Substations Demand sub-program.

A. The Company's LVD Substations Demand O&M sub-program includes expenses for emergent restoration and corrective maintenance on LVD substation equipment and facilities. This program includes work on the equipment, facilities, infrastructure, and property associated with LVD substations.

In addition, the Company is required to correct situations where equipment in substations violates National Electric Safety Code ("NESC") requirements for working space clearance (typically between live components in control panels and other panels, walls, etc.). The Company has committed to complete all this work by 2028 under a 10-year plan.

Q. Please describe the O&M expenses related to the LVD Substations Demand sub-program as shown in Exhibit A-125 (MPK-15), line 10.

A. The Company is projecting LVD Substations Demand O&M expenses of $6,398,000 in the projected test year, as set forth in Exhibit A-125 (MPK-15), line 10, column (f).

Q. Why is LVD Substations Demand O&M spending increasing relative to historical levels?

A. As with the two Substations Reliability O&M sub-programs, historical funding levels in this sub-program have not been sufficient to complete substation inspections on the

appropriate schedule as given in the ESR-1 guidelines, compelling the Company to defer needed work. The Company is increasing the O&M spending in all four substation O&M programs to get onto the nominal cycles provided in the ESR-1 guidelines and clear maintenance backlogs. The projected spending level in the instant case will accomplish this. More inspections in the two Substations Reliability O&M sub-programs will result in more issues to address in the two Substations Demand O&M sub-programs. Historically, every $1 spent in a Reliability O&M sub-program on inspections has yielded $1.70 in maintenance needs in the corresponding Demand O&M sub-program.

Q. Please describe the work related to the HVD Substations Demand sub-program.

A. The Company's HVD Substations Demand O&M sub-program includes expenses for unplanned and emergent restoration, as well as corrective maintenance on HVD and Strategic Customer substation equipment and facilities. In addition, the Company is required to correct several situations where equipment in substations violates NESC requirements for working space clearance (typically between live components in control panels and other panels, walls, etc.). The Company has committed to complete all this work by 2028 under a 10-year plan.

Q. Please describe the O&M expenses related to the HVD Substations Demand sub-program, as shown in Exhibit A-125 (MPK-15), line 11.

A. The Company is projecting HVD Substations Demand O&M expenses of $5,311,000 in the projected test year, as set forth in Exhibit A-125 (MPK-15), line 11, column (f).

Q. Why is HVD Substations Demand O&M spending increasing relative to historical levels?

A. As with the other substations O&M sub-programs, historical funding levels in this sub-program have not been sufficient to actually complete substation inspections on the appropriate schedule as given in the ESR-1 guidelines, compelling the Company to defer needed work. The Company is increasing the O&M spending in all four substation O&M programs to get onto the nominal cycles provided in the ESR-1 guidelines and clear maintenance backlogs, which as of April 2025 was approximately 2,500 substation demand orders. The projected spending level in the instant case will accomplish this.

Q. Please describe the benefits to customers provided by the LVD and HVD Substations Demand sub-programs.

A. Work identified through substation inspections reduces the potential for outages from unplanned events. These corrections are relatively quick and simple (e.g., lubricating bearings, realigning a switch, or adding SF6 to a gas circuit breaker) and can be achieved through spending in this program. Occasionally, the issues require equipment replacement that would be covered under one of the capital programs (such as HVD Lines and Substations Rehabilitation or HVD Lines and Subs Failures) and in some cases, such as a circuit breaker repair, an evaluation must be performed to determine if a procedure such as rebuilding the breaker is more cost effective than replacing the unit. Either way, it is almost always more cost efficient to perform the work in a planned manner than waiting for the unit to fail. This provides value to the customer and provides the best reliability. The projected spending increases will allow the Company to perform additional inspections and corrective maintenance.

Corrective Maintenance

Q. What work activities are carried out in the Corrective Maintenance O&M sub-program?

A. The Corrective Maintenance sub-program supports customer- and field-generated orders associated with imminent safety issues or system deficiencies, including emergent and short-term planned maintenance requirements. This most prominently consists of splicing wire on primary and secondary LVD lines, such as wires struck by trees during storms. This also consists of responding to underground faults, which takes longer than responding to those on the overhead system.

This sub-program ensures compliance with regulatory requirements, and supports the Company's safety and reliability objectives through maintenance to address safety issues and system deficiencies—this is most relevant regarding wire-down response, since this sub-program is used to splice wires damaged during storms.

Q. How does this work benefit customers?

A. The Corrective Maintenance sub-program improves public safety and reliability of the system by responding to customer reported concerns, and to damage from storms and other incidents, most critically by responding to the safety issues posed by broken wires.

While in some circumstances the Company will replace equipment and infrastructure to upgrade and improve the system, there are times when replacement is not the most cost-effective option. In these instances, a minor repair or modification that improves safety or reliability of the system can be made. For example, if a pole has minor damage, then the Company may make a minor repair to quickly restore a customer, and then not need to fully replace the pole until a later time.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 12, column (l), the Company is projecting to spend $5,236,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined by accounting for the expected level of work orders. This sub-program consists largely of labor costs, and is based on projected workplan hours to complete the work orders.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is being driven by an increase in labor costs. Each year, the Company's electric service workers receive a cost-of-living adjustment and union-negotiated merit increases in pay. Consequently, the average standard labor rate across the past five years is 16% lower than the average standard labor rate in the test year.

Staking

Q. Please describe the O&M expenses related to the Staking & Locating sub-program.

A. The Staking & Locating sub-program involves Company labor and contractor services for the staking and locating of the Company's electric distribution facilities, in accordance with the MISS DIG law (Public Act 174 of 2013 ("Act 174")), a key component of securing public and employee safety. Work is typically performed by a contracted outside service vendor on a multi-year contract with the Company.

Q. Please discuss the work activities in the Staking and Locating Sub-Program.

A. The Staking and Locating sub-program includes the following work activity categories:

- **Outside Services - Dedicated:** Contractor costs are included in the test year projection for staking and locating activities performed under the Dedicated Staking programs, under which contractors work solely for the Company.

- **Company Labor:** Volumes and hours are included in the test year projection for Company labor to support abnormal operating condition efforts.

- **Licenses, Permits & Fees**: Includes fees that Consumers Energy pays to the state MISS DIG 811 system as part of Act 174.

- **System:** Use of Irth Solutions UtiliSphere to enable ticket management and reporting for contracted staking and locating, MISS DIG ticket risk scoring to enable more effective and efficient excavator intervention, and work plan management and reporting.

Q. Has the Company made any changes to the above work activity categories since its last electric rate case?

A. Historically, the Company also had "Outside Services" contractor costs for staking and locating activities under a shared resource model, in which contractors would also work for other parties besides the Company. In 2023 and 2024, the Company started using dedicated contractors who only work for the Company. Based on realized performance improvements, the Company began transitioning to a fully dedicated staking contractor model in December 2024, and completed the transition in March 2025. Therefore, in the test year in the instant case, there are no costs for Outside Services for shared contractors.

Q. Why did the Company initially pursue a dedicated contractor staking strategy?

A. The Company originally pursued this in a limited portion of the Company's gas service territory because changes in the program were necessary to improve timeliness and accuracy of staking for public safety, especially given the continued ticket volume. When accuracy and timeliness of staking are off target, this creates negative behaviors with third-party excavators, resulting in unsafe digging practices. A critical step in ensuring safe digging practices is having excellence in stake-and-locate timeliness and accuracy. With a dedicated contractor staking strategy, the Company sought to achieve the following objectives in support of safe digging:

- The first key objective is *timeliness*. Through the dedicated workforce, the Company will see improved timeliness compared to historical performance to support the excavating community. This will be achieved by having a single utility focus for ticket management. This model improves the ability to manage ticket volume fluctuations throughout the year due to not having the risk of completing all other commitments on the ticket in the shared resource model.

- Another key objective is *quality*, with improved staking accuracy performance compared to recent historical data. This is expected to be achieved as stakers need only focus on one utility type, compared to the shared resource model, where stakers are responsible for all assets (electric, gas, communications, and water). This will lead to increased staking proficiency.

- The last key objective is *improved excavator communications* on projects. Improved communications with the excavating community will be enabled by use of enhanced positive response, which provides additional information and pictures to the ticket initiator, and an additional payment type for 180-day project tickets to assist in mitigating the risk of rushing.

Please note this transition to dedicated contractor staking has also been implemented in the Company's gas business, and is also discussed in detail by Company witness James P. Pnacek in the Company's most recent Gas Rate Case in Case No. U-21806.

Q. Why is the Company expanding its dedicated contractor staking to its entire service territory?

A. Based on initial benefit realizations, the Company planned to expand its Dedicated Contractor Staking Program to expand the benefits. The staking contract with the contractor that the Company used for its shared contractor approach was set to expire in the first quarter of 2025. In anticipation, the Company sent out a request for proposal in the third quarter of 2024 for staking services for the Company's remaining service territory that at the time was under the shared contractor resource model. The request included options for both shared and dedicated services. The bids yielded an average unit cost for the dedicated contractor resource model that was below the average unit cost of the shared

contractor staking model, by an average of $0.51 on a per unit basis. Based on the lower unit cost, the realized timeliness, and quality improvement from the dedicated contractor resource model, the Company elected to pursue the lower cost, dedicated contractor option and implement a statewide dedicated contractor staking approach for its entire service territory.

Q. What actual benefits from dedicated contractor staking did the Company realize in 2023 and 2024?

A. In 2023, with the initial implementation of the dedicated contractor resource model in place in two-thirds of Oakland County (compared to the shared contractor resources model used in 2022), the Company saw the following results:

- Gas accuracy related to at fault damage reduction improved by 87.3%.
- Field timeliness for the dedicated contractor model averaged 98.7% compared to 97.3% for the shared contractor resource model in 2023.

For 2024, with the dedicated contractor model expanded to cover Oakland County and Kent County, the Company saw the following results compared to the former shared contractor resources model:

- Gas distribution accuracy related to at fault damage reduction improved by 78% from 2022.
- Electric distribution accuracy related to at fault damage reduction improved by 80% from 2023.
- Field timeliness for the dedicated contractor model averaged 99.7% (including 24 hour re-transmits) compared to 95.1% for the shared contractor resource model in 2024.

Q. What benefits does the Company anticipate going forward?

A. The Company anticipates fully pursuing a dedicated contractor model will improve timeliness by 4-5%, allowing the Company to regularly achieve 98% or greater timeliness. The Company also expects that it will see a 50-75% reduction in damages caused by

third-party locating. Additionally, the Company believes dedicated contractors will lead to improved communication and partnership with the contractors.

Q. Please provide a breakdown of Staking and Locating sub-program expenses.

A. The Staking & Locating sub-program expenses for 2024 and the test year in this case are identified in Figure 49 below:

FIGURE 49
STAKING AND LOCATING SUB-PROGRAM PROJECTION BREAKDOWN BY ACTIVITY TYPE

Work Type	2024 Actual	Test Year
Outside Services – Staking and Locating	$3,356,806	$0
Outside Services – Dedicated electric staking and locating	$2,406,613	$13,249,346
Company labor	$0	$9,534
Licenses, Permits & MISS DIG Fees	$384,642	$689,338
Total Program	**$6,148,061**	**$13,948,218**

Q. What is the basis for determining the $13,948,218 of projected O&M expenses in the test year for this sub-program?

A. Spending in this sub-program is primarily driven by staking request volume (units). The primary drivers for increased spending in the test year in this case include:

(a) increase in the cost per ticket under the contracts with staking contractors ($6,760,338 total increase) includes dedicated model expansion;

(b) anticipated contractor volume increases ($725,589 total increase);

(c) Company labor and volume increase ($9,534 total increase); and

(d) increases in MISS DIG 811 membership fees ($304,696 total increase).

Q. Describe the test year forecast for volume and unit costs.

A. An anticipated unit cost increase is included in the test year projection for contractor services, in alignment with historical data and the requirement for enhanced capability to manage increased demand in performance and increasing labor costs.

The staking completed by an outside contracted vendor is billed based on contractual unit costs.

An anticipated volume increase of 7% is included in the test year projection relative to 2024 contractor services. This is in alignment with the historical data and staking forecasts for the state of Michigan. The anticipated contractor unit cost and staking volume increases are shown in the following table:

FIGURE 50
Historical Data and Unit Cost Staking Forecasts

Contractor Stake & Locate Services		
	Base Unit Forecast (units)	Base Unit cost ($/unit)
2024 Actual	433,137	$13.32
2025 Projected	446,893	$26.06
2026 Projected	478,176	$26.93
2027 Projected	511,648	$27.81

The Statewide MISS DIG 811 Annual Ticket Requests table below shows the change in staking volumes realized year over year.

MISS DIG 811 data[20] shows a continuous growth in staking and locating ticket requests for the entire state of Michigan, except for a small decline in 2020, which appears to be a temporary result of COVID-19 pandemic business impacts. Given a projected

[20] https://www.missdig811.org/about/who-we-are/about-miss-dig.html

increase in staking volumes tied to expansion of rural broadband internet infrastructure, growth is expected to further increase, going forward, to 7% per year.

The following is the historic and projected Statewide MISS DIG 811 annual ticket requests:

FIGURE 51
MISS DIG ANNUAL GROWTH

MISS DIG 811 Statewide Annual Growth[21]			
Years	**Annual Ticket Requests**	**Prior Year Requests**	**% Change**
2017	872,896	814,303	7.2%
2018	923,993	872,896	5.8%
2019	1,015,753	923,993	9.9%
2020	994,573	1,015,753	-2.1%
2021	1,088,030	994,573	9.4%
2022	1,093,021 *	1,088,030	0.5%
2023	1,202,992	1,093,021 *	10.1%
2024	1,327,894	1,202,992	10%
2025 Forecast	1,420,847	1,327,894	7% (assumed)
2026 Forecast	1,520,306	1,420,847	7% (assumed)
2027 Forecast	1,626,727	1,520,306	7% (assumed)

*Volume impacted by MISS DIG 811 Pelican implementation

Q. Please describe the Company's concerns with the increase in staking ticket volumes and proposed recommendation.

A. The Company has estimated staking tickets for the test year based on the best information available at this time. With staking requests increasing due to fiber optics and other infrastructure work, the actual staking demand the Company experiences in 2026 could be

[21] MISS DIG 811 Data Reference - https://www.missdig811.org/about/who-we-are/about-miss-dig.html

above the Company's staking volume forecast. While the Company attempts to forecast staking volumes with a high degree of accuracy, the largest factors influencing expenditures in these programs are externally driven. As a result, the Company requests it be allowed to defer for refund or recovery of any O&M expenses for this program, below or above amounts included in rates for the test year; this treatment was also requested by the Company in the Company's most recent Gas Rate Case in Case No. U-21806. This request would avoid potential constraints on other important programs if higher than anticipated staking costs outside the Company's control are incurred. It would also prevent customers from paying for costs that were not incurred if staking volumes are below forecasted levels.

The Company is basing its deferral request mainly on two high-speed internet infrastructure grant programs administered by the Michigan High-Speed Internet Office ("MIHI") located within the Prosperity Division of the Department of Labor and Economic Opportunity. The first program is Realizing Opportunities with Broadband Infrastructure Networks ("ROBIN"). The second program is the Broadband Equity, Access, and Deployment Program ("BEAD").

Q. Please describe the test year costs related to dedicated locating.

A. In the interest of public safety, damage prevention, and in compliance with a facility owner's obligation under Act 174, the act of placing marks to indicate approximate facility location in response to a MISS DIG ticket requested in advance of excavation activity, an anticipated increase in volume and costs are included in the test year projection for dedicated locating. This includes resources to locate *only* for Consumers Energy facilities, contrasted to the existing method of vendors locating several other additional external

facilities. This focus substantially mitigates public safety, damage, timeliness, quality, and communication risks with excavators in some of the highest areas for staking requests for Consumers Energy, encompassing 100% of requests starting in April of 2025.

Q. Please describe the Company's plan to expand the Dedicated Contractor Staking Program.

A. Based on existing benefit realization for the Dedicated Contractor Staking Program, the Company plans to expand the program to continue to improve public safety, reduce damages, mitigate communication risks with excavators, improve quality, and comply with the timeliness requirement within Act 174.

In 2024, Kent and Oakland counties were managed under the Dedicated Staking model accounting for 17% of the total staking ticket volumes. In 2025, the Company plans to expand the Dedicated Contractor Staking Program to include the Company's entire statewide electric service territory and cover up to 100% of the total staking ticket volume. The dedicated model will already be fully implemented during the test year.

Q. Why did the Company choose to start the Dedicated Contractor Staking Program instead of hiring more contract stakers to improve staking quality?

A. Hiring additional contractors would follow the shared resource model, which shares staking resources with other companies and assets.

The shared resource model carries risks, including skilling proficiencies related to delivering timeliness and quality performance as it relates to staking existing infrastructure. The Dedicated Contractor Staking Program uses a dedicated resource for Company assets *only*, so stakers can become efficient and proficient on Company asset staking without having to focus on other facilities such as communications, water, etc.

The dedicated workforce model substantially mitigates many of the risks associated with the shared resources model as described earlier in this section.

Q. Please explain the MISS DIG cost increase.

A. MISS DIG 811 costs were assessed in 2023 by the MISS DIG Board, and adjusted as of January 2024 based on actual utilization for members, which resulted in an increase for the Company.

Meter Services and Credits

Q. What work activities are carried out in the Meter Services and Credits O&M sub-program?

A. This O&M sub-program funds Electric Meter Operations ("EMO"), whose expenses are partially offset by first-set and retirement credits of both electric meters and metering transformers.

When the Company buys meters, it capitalizes them the first time they are installed (including labor) in the Metering capital program; the first-set credit offsets O&M and reduces O&M by the amount being capitalized. When a meter is retired, a retirement O&M credit is issued against cost of removal.

EMO responds to customer-initiated and Company-generated orders for installation, replacement or repair, and inspection of new and existing metering installations to ensure customers have a safe, reliable, and accurate metering installation. This sub-program also installs, removes, and maintains demand response and power quality installations.

Q. Please explain the Credit portion of this O&M program.

A. Meters and metering transformers are purchased through the LVD Metering capital sub-program, discussed by Company witness Partlan in her direct testimony. In addition to the direct cost for electric meters and metering transformers, a first-set credit value is included to offset the cost of labor for installation. When electric meters and metering transformers are purchased and received, the first-set credit value for each meter is totaled at the end of each month and credited back to O&M for the installation labor. When electric meters and metering transformers are retired, the cost of removal credit is totaled at the end of each month and credited back to O&M for the final removal labor. The credits are intended to partially offset the labor costs associated with new and retired metering installations.

Q. How does this work benefit customers?

A. This work benefits customers by ensuring that all customers, from residential to commercial and industrial ("C&I") and generation and transmission interconnections, have reliable and accurate billing information. Additionally, smart meters are required for customers to participate in programs like time of use rates, to see their usage in the customer portal, etc.

Metering also impacts reliability. Metering infrastructure is aging, with some metering transformers more than 60 years old. The Company continues to inspect and maintain these transformers, but eventually more intentional replacements of wiring and other components are needed to prevent meter failures that would cause outage minutes.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 14, column (l), the Company is projecting to spend $17,088,000 in the test year on meter services. As shown in Exhibit A-124 (MPK-14), line 15, column (l), the Company is projecting $10,257,000 in meter credits in the test year. This results in a net expense of $6,831,000 for the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined by considering projected workload. The Company projects a volume of work based on historical data and expected growth from areas like New Business. Workload projections assume a certain number of hours to do given work, based on historical productivity, which is translated into expenses for meter installations. Total credits are based on projections for new meter capital purchases, and projections for retirements. The credit rate calculation is determined monthly, which is calculated considering labor, vehicle loadings, and non-premise cost. These amounts are then apportioned by an electric mix factor (a portion of the meters are installed by EMO and others by Distribution) and then multiplied by the average time required to either install (for first set credits) or remove (for retirement credits) a meter. This calculation varies based on meter or transformer type.

As an example, for November 2024, for a single-phase, 200 Amp, smart meter, the calculated 1st set credit was as follows:

Figure 52
Example of Credit Rate Calculation

	Distribution	EMO
Standard Labor Rate	$ 98.51	$ 73.64
+		
Standard Labor Rate * Vehicle Loading		
Standard Labor Rate	$ 98.51	$ 73.64
Vehicle Loading	0.01	0.15
	$ 0.99	$ 11.05
+		
Standard Labor Rate * Non-Premise		
Standard Labor Rate	$ 98.51	$ 73.64
Non-Premise	0.43	1.6
	$ 42.36	$ 117.82
=		
Loaded Hourly Rate	$ 141.85	$ 202.51
*		
Electric Meter Mix	0.22	0.78
=	$ 31.21	$ 157.96
Blended Loaded Hourly Rate	$ 189.17	
*		
Average Install Time (hr)	0.23	
=		
1st Set Credit Rate	$ 43.51	

The retirement credit rate is calculated using the same methodology, with the exception that instead of the average install time, the average remove time is used, in this case, 0.13 hr, resulting in a retirement credit rate of $25.22 per unit.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The level of credits in this sub-program remains relatively flat for the next several years, partially due to inventory carried over from previous years of meters. However, because of this carried over inventory, the Company is not making as many capital purchases of meters. This means that EMO work is spread over fewer capital purchases, which makes Meter Services expenses higher.

Streetlighting

Q. What work activities are carried out in the Streetlighting O&M sub-program?

A. Streetlighting O&M supports the personnel and materials necessary to complete streetlight maintenance activities. Examples of Streetlighting O&M expenses include: underground fault investigations, minor repairs including conductor splicing and replacement of photo cells, and shield installation on light-emitting diode luminaires.

Q. How does this work benefit customers?

A. Streetlights provide illumination to enhance safety and the aesthetics of roadways, residential areas, and cityscapes in various applications throughout the Company's service territory. This work complements the capital investment in company owned streetlights.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 16, column (l), the Company is projecting to spend $2,089,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on historical O&M expenses, and an increased focus on long-duration outage investigation and repair.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is being driven by increased time spent investigating, locating, and repairing underground-fed lights. Activities associated with failure investigation, locating, and repair of underground-supplied lights include: additional hydro excavation, on-site trouble shooting, and splicing.

Service Calls

Q. What work activities are carried out in the Service Calls O&M sub-program?

A. In the Service Calls sub-program, the Company responds to various types of requests from customers, including disconnections and reconnections, undergrounding service lines, upgrading service lines to higher capacity, and installing temporary service lines to support house construction. Customers pay for some requested work, but not for disconnections and reconnections, and the Company incurs O&M costs not billable to the customer for all types of Service Call work. The Company estimates, based on historical numbers, that employees will respond to approximately 33,000 discrete service calls annually. This O&M sub-program funds these responses.

Q. How does this work benefit customers?

A. This work benefits customers by responding to their expressed specific needs for electric service.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 17, column (l), the Company is projecting to spend $5,699,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined primarily by considering historical work order volumes. The estimated number of service calls in the Company's workplan is based on the previous year's completed work. The number of completed work orders for each month in the previous year is totaled and used as an estimate of forecasted work per month for the future year. Projected costs are directly based on the number of projected work orders.

The Company translates the projected work orders into projected workplan hours to complete the work, and multiplies this by labor costs.

In addition to projected workplan hours, the Company also adds in non-labor spending, which are simply projected to remain at historical levels.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending in the test year is being driven by an increase in labor. Each year, the Company's electric service workers receive a cost-of-living adjustment and union-negotiated merit increases in pay. Consequently, the average standard labor rate across the past five years is 16% lower than the average standard labor rate in the test year. In addition to the labor rate increase, the Company is projecting a 17% increase in hours work during the test year, compared to the historical five-year level.

Alma Equipment Repair

Q. What work activities are carried out in the Alma Equipment Repair O&M sub-program?

A. The Company's Alma Equipment Repair O&M sub-program, based at the Company's Alma Service Center, includes maintenance activities (testing, repairing, reconditioning) for assets such as mobile substation equipment, substation oil processing equipment, and substation power transformer cooling equipment. End-of-life retirement of failed and aged electrical equipment such as regulators, reclosers, and pole top transformers is also handled through this program. The sub-program also includes activities such as substation equipment acceptance testing and ensuring compliance with all environmental regulations

regarding the handling, storage, and disposal of equipment containing polychlorinated biphenyl ("PCBs").

Q. How does this work benefit customers?

A. These activities are considered base level maintenance for system reliability and emergency response to demand outages. In particular, mobile substations need to be properly maintained so they are in good working order and can be deployed for field use when needed. The Alma Equipment Repair O&M sub-program can also identify savings for customers. For example, quickly repairing equipment like regulators, when possible, represents savings when compared to capital replacements; when the Company identifies damaged materials, Alma Equipment Repair employees assess if it can be fixed and returned to service or if it must be scrapped and replaced, based on relative costs.

Additionally, the Alma Equipment Repair O&M sub-program supports safety by ensuring safe disposal of hazardous substances, and offsets some costs by selling used transformer oil to parties who can use or recycle it.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 18, column (l), the Company is projecting to spend $571,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on anticipated headcount levels and the volume of work expected to be done. Both headcount and workload have been relatively consistent in this sub-program in recent years, and projected test year spending is closely in line with recent actuals. Test year spending is slightly higher than the five-year average

to account for increased maintenance volume, with more mobile substations having been purchased by the Company.

Meter Reading

Q. What work activities are carried out in the Meter Reading O&M sub-program?

A. The Meter Reading O&M sub-program includes Company employee labor, business expenses (e.g., fleet and training costs), and technology expenses (e.g., hardware and software maintenance, cellular, and system improvements) for purposes of obtaining meter indexes for the calculation of customer bills.

The Company has a single Meter Reading workforce for both electric and gas meters, in large part due to the ongoing need to manually read a small amount of meters each month (approximately 16,000 electric meters and 16,000 gas meters in the Company's service territory). This workforce also performs inspection of padmounted transformers/enclosures, a strategy for keeping overall costs down; because the manual-read meters are spread out geographically, the Meter Reading workforce performs these inspections while enroute to meter locations. The Company also meets regulatory requirements by maintaining sufficient meter reading resources.

Because the Meter Reading O&M sub-program is managed jointly for the Company's electric and natural gas operations, the total meter reading costs are allocated between electric and natural gas.

Q. How does this work benefit customers?

A. This work benefits customers by ensuring all customers have accurate meter reads.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 19, column (l), the Company is projecting to spend $1,971,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined by considering the projected volume of work for the meter reading group and then allocating between the electric and gas businesses. Allocations are typically split 60/40 in favor of gas.

Meter Technology and Management System Support

Q. What work activities are carried out in the Meter Technology and Management System Support O&M sub-program?

A. The Meter Technology and Management System Support O&M sub-program funds the MTC activities to support the Metering capital sub-program. Activities performed by the MTC include:

- Electric meter and metering transformer testing for accuracy and function in accordance with MPSC rules governing meter accuracy and testing requirements;
- Evaluation of new metering and meter communications technology;
- Lifecycle assessment testing;
- Device management, including metering equipment purchase planning and meter work order troubleshooting and support;
- Order fulfillment for field operations for metering equipment;
- Daily interrogations of the Company's AMI electric meters; and
- Maintenance of hardware and software firmware in the AMI electric meter population.

This sub-program has also taken over funding of the Smart Energy Operations Center ("SEOC") from the Field Operations O&M program, which is outlined later in my direct testimony.

Q. How does this work benefit customers?

A. This work benefits customers by ensuring all customers, from residential to C&I and generation and transmission interconnections, have reliable and accurate billing information. This operation maintains the health of the electric smart meters, and enables customers to participate in programs, such as the time-of-use program, and the ability to have more granular information about their energy consumption through a Web portal. The testing performed at the MTC keeps the Company in compliance with MPSC metering rule requirements, as the annual meter routine sampling program is performed at the MTC. Additionally, the sub-program funds technical assessment of new metering and communications equipment related to meters, and assessment of new devices that can benefit customers through programs such as load monitoring or load control devices.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 20, column (l), the Company is projecting to spend $1,393,000 in the test year.

Q. How were these spending amounts determined?

A. The level of spending for this program is made up of three components: Salaried labor, Union labor, and business expenses. The spending for each year is based on the current headcount, including any approved vacancies with the applicable labor costs for each, including inflation and expected labor increases. In addition, the projected spending for this program considers any planned promotions and known business expenses that are

planned for the subsequent years. Spending in this program has remained relatively flat for most of the last five years.

Smart Energy MTC

Q. What work activities are carried out in the Smart Energy MTC O&M sub-program?

A. The Smart Energy MTC sub-program consists of four components:

1. Communications backhaul for both Smart Meters and Cellular-Under-Glass legacy meters. Specifically, the Company's electric smart meters all provide billing determinants and metering events through cellular communications, and the Company pays cellular charges per meter monthly.
2. Meter software maintenance charges.
3. Technical support service charges from the Company's smart meter supplier.

Q. How does this work benefit customers?

A. This work benefits customers by ensuring all customers, from residential to C&I and generation and transmission interconnections, have reliable and accurate billing information. This operation maintains the health of the electric smart meters, and enables customers to participate in programs, such as the time-of-use program, and the ability to have more granular information about their energy consumption through a Web portal and to realize the benefits of smart meter technology.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 21, column (l), the Company is projecting to spend $9,226,000 in the test year.

Q. How were these spending amounts determined?

A. The charges underlying these spending amounts are fixed by a contract that establishes the charging rates through 2032. These rates are based on the number of active electric smart meters the Company has installed at customer locations, and meter inventory levels

required to meet new business and meter failure requirements throughout the year. As these charges are fixed, the spending forecast is based on the projected number of meters, and is adjusted annually based on projections for new business, regulatory requirements, or other large projects. Spending in this program has remained relatively flat for the last five years, and that trend should continue in coming years.

D. Service Restoration

Q. Please describe the O&M work and expenses related to the Service Restoration sub-program.

A. Company witness Snider discusses the entirety of this sub-program in his direct testimony. Service Restoration O&M expenses are projected to be $214,344,000 in the bridge period and $165,215,000 in test year. O&M dollars in this sub-program support activities described within Company witness Snider's direct testimony.

E. Field Operations

Q. Please describe the O&M work related to the Field Operations Program.

A. The Field Operations Program consists of the cost of training, supervision, facilities, and facilities maintenance for the Company's in-field operations teams.

These costs are planned annually based on the expected costs to maintain an in-field operations team to carry out the various activities required for supporting the safe, reliable, and efficient operations of the electric distribution system. This program includes labor expenses for supervision and leadership for electric LVD and HVD operations. Expenses include the cost of training, supervision, facilities, and facilities maintenance for in-field operations teams.

Q. What are the sub-programs in the Field Operations O&M Expense Program?

A. These sub-programs, as shown in Exhibit A-125 (MPK-15), lines 25 through 33, are:

1. Training;
2. Tools;
3. Field Operations Expenses;
4. Indirect Labor/Labor Variation;
5. Supervision/Admin Staff;
6. SEOC;
7. Grid Management—Distribution;
8. HVD Lines Construction Workforce; and
9. Underground Workforce.

However, there is no projected test year spending for the Indirect Labor/Labor Variations or the SEOC sub-programs (as noted above, the SEOC is now funded through the Meter Tech and Management System Support sub-program). There is also no projected test year spending for HVD Lines Construction Workforce.

Training

Q. What work activities are carried out in the Training O&M sub-program?

A. The Training sub-program covers expenses whenever groups in the Electric Operations organization conduct official training courses, generally at the Company's Marshall Training Center or another designated training location, typically with a course instructor. These training courses include skills-based training using both classroom time and instructor-led fieldwork at the training location for Electric Operations employees, including Electric Lines, Substation Operators and Maintenance, Electric Field Lab, and Electric Meter Operations. For example, a training course for lineworkers to move from

the Step 1 to the Step 2 classification involves about three weeks of training at the Marshall Training Center. The Company also uses on-the-job training in the field for many purposes, and that is not part of the Training O&M sub-program; those costs are instead charged to the actual job in the field being completed.

The Training O&M sub-program also includes expenses for operating the Company's Apprenticeship Program, including paychecks earned by apprentices while they are at the training center. Aside from the Apprenticeship Program, union labor associated with additional hours of training, such as continuing education and required annual training courses, are also paid out of the Training O&M sub-program. Full-time and temporary union instructors who administer the training are also funded in this sub-program.

Q. How does this work benefit customers?

A. This work benefits customers by ensuring the Company has enough employees with the required training to have the skills to complete field work, and ensuring employees are properly trained in safety procedures.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 25, column (l), the Company is projecting to spend $15,833,000 in the test year.

Q. How were these spending amounts determined?

A. The expenses for this sub-program were determined based on the number of employees, apprentices, and external candidates, multiplied by the expected hours training they will receive each year.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is being driven by the Company's projected increased headcount in its field operations workforce, which in turn increases the training expenses that must be incurred.

Tools

Q. What work activities are carried out in the Tools O&M sub-program?

A. The Tools O&M sub-program includes the cost of procuring tools valued under $1,000, including the U.S. Department of Labor's Occupational Safety and Health Administration ("OSHA") safety devices, testing equipment, and utility-specific industry tools, particularly fire-retardant clothing.

This equipment is required to maintain, inspect, and re-calibrate the equipment on Company trucks for use in the field. The Tools O&M sub-program also includes expenses related to tool repairs.

Q. How does this work benefit customers?

A. This work enables a safer, faster response to outages, safe and efficient installation of new services, and more productive completion of projects with less waste and lower unit costs. In general, adequate tools are required to complete field work to improve reliability and restore service. Some tools, such as fire-retardant clothing and other personal protective equipment are essential for employee safety and are required by OSHA regulations.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 26, column (l), the Company is projecting to spend $1,982,000 in the test year.

Q. How was this spending amount determined?

A. This spending amount is determined based on the size of the field operations workforce, which in turn determines how many tools, including fire-retardant clothing and personal protective equipment, the Company needs.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The modest increase in spending in this sub-program is being driven by the Company's projected increase in its field operations workforce to support the Reliability Roadmap.

Field Operations Expenses

Q. What work activities are carried out in the Field Operations Expenses O&M sub-program?

A. The Field Operations Expenses sub-program consists of the cost of overhead expenses in support of the Company's in-field operations team. For electric lineworkers, substation workers, and electric service workers, this sub-program covers most of their expenses outside of salaries: travel expenses, meals, and field mobility costs for things like phones and internet connectivity in the field.

Q. How does this work benefit customers?

A. This work benefits customers by enabling employees to do their jobs in the field, completing reliability projects and other work that benefits customers. These expenses ensure that employees can travel to where work is needed.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 27, column (l), the Company is projecting to spend $2,608,000 in the test year.

Q. How were these spending amounts determined?

A. These costs are planned annually, based on the expected costs to support an in-field operations team to carry out the various activities required for supporting the safe, reliable, and efficient operations of the electric distribution system. In general, projected spending is heavily based on historical actuals, with adjustments based on apprentices hired that will increase total headcount, and based on any increases in items such as the cost of travel and telecommunications.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is being driven by the Company's increased headcount in its field operations workforce, which in turn increases the total expenses incurred.

Supervision/Admin Staff

Q. What work activities are carried out in the Supervision/Admin Staff O&M sub-program?

A. This sub-program includes the salaries and expenses of the supervision and leadership (at the first-line supervisor level) for Electric Operations, to ensure safe operation of facilities and adherence to Company policies.

Salaries and expenses fund O&M Supervision in Electric LVD, Customer Field Services, Electric System Substation, Electric System HVD, Substation Construction, Electric Work Methods and Tools (governing skills training for existing workforce), and the Electric Joint Committee (governing training for apprentices).

Q. How does this work benefit customers?

A. This work benefits customers by funding the field supervision necessary for completing work in the field, and the supervision required in certain training situations to ensure the Company continues to have an adequate workforce.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 29, column (l), the Company is projecting to spend $5,312,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on projected headcounts and the salaries for those employees.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is driven by increased number of supervisors to support the growth in the workforce needed to deliver the Reliability Roadmap

Grid Management – Distribution

Q. What work activities are carried out in the Grid Management – Distribution O&M sub-program?

A. Grid Management is responsible for providing statewide 24/7 monitoring and control of the LVD and HVD systems. This includes providing statewide dispatch of electric field resources to respond to electric service interruptions, electrical hazards, and other calls related to electric services reported by customers. Grid Management coordinates and administers planned work supporting electric reliability projects, maintenance work, and customer-related work on the HVD and LVD systems. Grid Management is also

responsible for the coordination of major electric service restoration efforts associated with storms and other natural disasters. Lastly, Grid Management is responsible for operating grid automation devices and using advanced applications to improve system reliability, reduce outage duration, ensure power quality within MPSC regulations, and reduce energy waste. O&M expenses in this program are for the salaries and expenses of operating and support function employees at the control and dispatch centers that the Company operates.

Q. How does this work benefit customers?

A. This work benefits customers by allowing for the timely restoration of electric service, securing and clearing of electrical hazards impacting public safety, isolating failed equipment and performing partial service restorations, remotely operating field devices to reduce outages during and mitigate emergency conditions impacting the system or the public.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 31, column (l), the Company is projecting to spend $4,271,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on employee salaries for the necessary headcount to fill the operating and support roles in the program, representing an amount of $3,383,000. Additionally, expenses associated with each department in the program, as well as annual software maintenance fees, communication maintenance costs and fees, and substation communication equipment demand maintenance costs, are in the amount of $580,000. Lastly, O&M related project costs associated with the Unified Control Center

project as referenced in Company witness Snider's testimony are included in this program in the amount of $308,000.

Underground Workforce

Q. Please describe the O&M work related to the Underground Workforce Program as shown in Exhibit A-124 (MPK-14), line 33.

A. The Underground Workforce Program is responsible for both the undergrounding work in subdivisions and new business services, relocations, and reliability projects, plus future undergrounding the Company expects to pursue through the Reliability Roadmap and is proposing to resume in the test year of the instant case. The group can also perform replacement of failed underground and new underground construction for LVD overhead lines replacement.

Q. What is the Company's projected test year spending level for this sub-program?

A. As shown in Exhibit A-124 (MPK-14), line 32, column (l), the Company is projecting test year spending of $2,236,000.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on the workforce necessary to perform undergrounding for new business and failure work, representing an amount of $1,106,000. Additionally, it is based on the workforce necessary for future undergrounding the Company expects to pursue through the Reliability Roadmap, representing $1,130,000.

F. Compliance and Controls

Q. Please describe the work related to the Compliance and Controls O&M expenses.

A. Historically, Compliance and Controls O&M expenses have supported activities and personnel to maintain compliance with required regulations, and to provide oversight and

controls to contractor resources. However, the Company is not projecting any bridge period or test year spending on this line item in this case.

G. Planning and Scheduling

Q. Please describe the work related to the Planning and Scheduling Program as shown on Exhibit A-125 (MPK-15), line 40.

A. Planning and long-cycle scheduling was moved to Work Management and Customer Delivery in 2021. There is no planned spending in Distribution for the Planning and Scheduling Program for the bridge period or test year.

H. Work Management and Customer Delivery

Q. Please describe the Work Management and Customer Delivery Program as shown on Exhibit A-125 (MPK-15), line 43.

A. The Company formerly had an organization called Operations Performance, responsible for implementing process improvement and transformation projects to improve efficiency and quality.

This included business plan deployment for increased visual management, problem solving, and standard work to achieve key Company objectives of Safety, Customer Experience, On-Time Commitments, Reliability, Resiliency, and Waste Elimination. The Planning and Scheduling, Contract Administration, and Resource Planning & Closeout teams were brought into Operations Performance in February 2021, as reflected in Exhibit A-124 (MPK-14), lines 37 through 43, columns (b) and (c). This meant that Operations Performance included responsibility for weekly and long-range planning and scheduling for a variety of Electric Operations fieldwork.

In March 2024, a Company reorganization led to the Operations Performance organization being disbanded, with employees and work transferred elsewhere. The Operations Performance Program had included technology expenses in the form of labor to support field work and systems, meter reading systems, order system upgrades, productivity applications, data and analytics systems, field call-out system maintenance, and upgrade vendor fees. These functions related to IT were moved to the Company's IT organization.

Functions related to industrial engineering, or "lean" processes, were also spun off and are now covered in the testimony and exhibits of Company witness Richard T. Blumenstock. The remaining work, largely concerned with planning and scheduling and related activities, is now classified in the Work Management and Customer Delivery program, which replaces Operations Performance in Exhibit A-124 (MPK-14), line 40, and in corresponding lines of my other O&M exhibits.

- As it is now structured, Work Management and Customer Delivery includes functions for Distribution Planning, Scheduling, Close-Out and Admin, and CEM. Planning ensures the operating plan adheres to the Company's business plan for Electric Operations field work.

- Scheduling ensures field crews have enough work, ready-work, and the right work and resources to complete the work plan.

- The Close Out and Admin functions ensure technical documentation is accurate and complete, and the costs of the work settle appropriately to the work orders.

- The CEM team is focused on meeting customer needs by providing a single point of contact for customer-requested service and meter installations, and alterations. CEM is responsible for ensuring all new customer service requests and customer-requested alterations on the Company's distribution system are coordinated from initiation through completion to meet customer expectations.

Q. Please describe the O&M expenses related to the Work Management and Customer Delivery Program.

A. The Company is projecting Work Management and Customer Delivery O&M expenses of $1,917,000 the projected test year, as shown in Exhibit A-124 (MPK-14), line 43, column (l). This spending level is primarily based on projected headcount in the organization.

I. Operations Management

Q. Please describe the Operations Management Program.

A. The Operations Management Program includes the salaries and expenses for senior management staff, as well as chargebacks from internal departments, specifically related to the operations of the electric distribution grid. This program also includes the electric portion of the reserves for incentive program accruals, injuries and damages, and electric claims.

Q. Please describe the O&M expenses related to the Operations Management sub-program as shown on Exhibit A-125 (MPK-15), line 44.

A. The Company is projecting Operations Management O&M expenses $1,955,000 in the projected test year, as shown in Exhibit A-125 (MPK-15), line 44, column (f).

The O&M projection in this sub-program is comprised of the salary and expenses for certain Electric Operations leaders as well as chargebacks from Supply Chain, Environmental, and Real Estate.

The salaries for the test year are projected using planned headcount and current salary plus inflation. Additional expenses are determined using a mixture of historic averages, current trends, and inflation.

IX. ELECTRIC ENGINEERING AND SUPPORT

Q. What are the programs contained within the Electric Engineering O&M section found in Exhibit A-126 (MPK-16)?

A. Electric Engineering O&M is separated into the following programs:

- Engineering Support
- Electric Distribution Management
- Electric Distribution - LVD
- Electric Distribution - HVD
- Electric Distribution Strategy
- Wildfire Mitigation

A. Engineering Support

Q. Please describe the Engineering Support Program.

A. Expenses under this program consist of salaries and expenses for Damage Claims/Prevention.

Damage Claims/Prevention expenses include salaries, non-exempt wages, and business expenses (travel, training, contractor costs, cell phone charges, fleet chargebacks, etc.) for Damage Claims and Damage Prevention employees.

These employees oversee the staking and locating of underground facilities in the Staking O&M sub-program described earlier in my direct testimony.

Q. Please describe the O&M expenses related to Engineering Support, as shown on Exhibit A-124 (MPK-14), line 47.

A. The Company is projecting Engineering Support O&M expenses of $1,277,000 in the projected test year. This amount is based on the number of employees, and is in line with the test year amount approved by the Commission in Case No. U-21585.

B. Electric Distribution Management

Q. Please describe the Electric Distribution Management Program.

A. The Electric Distribution Management Program expenses include salaries for the Electric Distribution engineering leadership team and their support staff.

Q. What is the Company's projected test year spending for the Electric Distribution Management Program?

A. As shown in Exhibit A-124 (MPK-14), line 48, column (l), projected spending for this program is $174,000 in the test year. This is in line with recent levels, and with the amount approved in Case No. U-21585.

C. Electric Distribution – LVD

Q. Please describe the Electric Distribution – LVD Program shown on Exhibit A-124 (MPK-14), line 49.

A. Expenses in this program cover salaries and expenses for the Company's LVD Engineering organization, which includes the Company's LVD Planning, LVD Design, Joint Pole Rental, and Grid Automation teams.

Q. Please explain LVD Planning.

A. LVD Planning expenses primarily include the O&M portion of salaries, business expenses, and training for LVD Planning employees. LVD Planning personnel perform security

inspections on at least one-half of the overhead LVD system each year, and initiate corrections to defects they find. They plan, develop the scope, and initiate projects that:

- Correct LVD system planning criteria violations found by performing power flow analyses on the Company's LVD circuits;
- Improve reliability for LVD infrastructure;
- Serve C&I customer load additions connected to the LVD system; and
- Further the modernization of the distribution system.

They also support the Company's stray voltage mitigation program by performing inspections to validate proper installation and operation of the installed mitigation equipment.

Q. Please describe LVD Design.

A. LVD Design expenses primarily include the O&M portion of salaries, business expenses, and training for LVD Design personnel. These personnel create designs for connecting new C&I customers to the LVD system as well as designs for projects that improve reliability or upgrade the capacity of the LVD system.

Additionally, the LVD Design team also creates designs for relocations, third-party work such as Michigan Department of Transportation, pole attachments such as cable or communication cables, and streetlight conversions such as center suspension conversions.

Q. Please describe Joint Pole Rental.

A. Joint Pole Rental includes expenses associated with jointly using poles with other utilities (e.g., telecommunications).

Expenses include attaching electric facilities to telecommunications provider poles. Sharing poles, where possible, saves the Company money by reducing the need to solely

install and maintain all Company-owned poles. Expenses are determined by contractual formulas defined by Joint Use Agreements with telecommunications providers.

Q. What is Grid Automation?

A. The Grid Automation team consists of personnel primarily responsible for planning and developing the Company's Grid Automation programs and projects, as described in the testimony of Company witness McPhail.

Q. What is the Company's projected spending for the Electric Distribution – LVD Program?

A. As shown in Exhibit A-124 (MPK-14), line 49, the Company is projecting Electric Distribution – LVD expenses of $11,773,000 in the test year. This is an increase from earlier years, and it is largely attributable to the increased amount of LVD planning and LVD design work necessary to support the increased number of LVD projects being identified as part of the Reliability Roadmap. It is also attributable to increased Grid Automation work to support the programs and projects described in the testimony of Company witness McPhail.

D. <u>Electric Distribution – HVD</u>

Q. Please describe the Electric Distribution – HVD Program as shown on Exhibit A-124 (MPK-14), line 50.

A. The Electric Distribution – HVD Program includes salaries and expenses for the distribution functions of the Company's HVD Engineering organization, including HVD planning work, HVD design work, system protection, standards management, and project engineering.

Q. Please explain HVD planning work.

A. HVD planning expenses primarily include the O&M portion of salaries, business expenses, and training for personnel performing HVD planning functions.

HVD planning personnel plan, develop the scope, and initiate projects that correct HVD system planning criteria violations found by performing power flow analyses on the Company's HVD system, and to correct HVD system issues related to poor reliability or poor asset health. They plan, develop the scope, and initiate projects that:

- Improve reliability for HVD infrastructure; and
- Serve large industrial customer load additions connected to the HVD system.

They also perform generator interconnection studies, plan and develop the scope, and initiate projects to connect DERs to the HVD system and LVD substations. HVD planning O&M expenses also include payment of NERC annual dues for the Company, and expenses related to helicopter inspections of the HVD system.

Q. Please explain HVD design work.

A. HVD design personnel create designs for connecting new industrial customers to the HVD system as well as designs for projects that improve reliability or upgrade the capacity of the HVD system for both lines and substation projects.

Q. Please explain system protection planning work.

A. System protection planning expenses primarily include the O&M portion of salaries, business expenses, and training for system protection planning personnel, relay maintenance costs, and relay scheme communications costs.

System protection planning employees are responsible for the protection systems across LVD, HVD, and generation. These responsibilities include:

- Developing the engineering specifications and standards for protection systems;
- Creating and maintaining the Company's electric short circuit models that are used when performing protective device coordination studies;
- Developing settings on protective devices installed across the Company's electric system;
- Developing maintenance programs for protection devices; and
- Ensuring compliance with applicable NERC standards.

System protection planning employees analyze electric system events that caused HVD and LVD circuits, substation components, and generating plant equipment to open via protective relay activation to ensure that fault conditions were recognized properly, and that electric system interrupting devices (like substation circuit breakers) operated correctly.

System protection planning employees also work closely with HVD planning personnel when performing generator interconnection studies to ensure interconnecting generators install proper protective relays and schemes that coordinate with Company protective relays and schemes.

Q. Please describe standards management.

A. Standards management personnel provide direction to the Engineering and Operations organizations regarding Company policy, engineering, and construction standards and materials for the distribution system. In addition, they manage the engineering records throughout their life cycle for the Company's generation and electric distribution assets. Finally, they also manage work orders for HVD materials and equipment in support of Property Accounting.

Q. What are the Company's projected test year expenses for Electric Distribution – HVD?

A. As shown in Exhibit A-124 (MPK-14), line 50, projected test year spending is $7,199,000. This is in line with recent levels, with a slight increase to account for increasing amounts of planned HVD work in the Reliability Roadmap and increasing expenses for HVD planning to support this.

E. Electric Distribution Strategy

Q. Please describe the O&M expenses related to the Electric Distribution Strategy Program.

A. The Electric Distribution Strategy Program expenses include salaries for the Distribution Strategy team, who is responsible for leading engagement activities for Distribution with stakeholders throughout the state, developing the long-term strategy for the organization, and helping to manage the organization's capital budget.

Q. What is the Company's projected test year spending for Electric Distribution Strategy?

A. As shown in Exhibit A-124 (MPK-14), line 51, projected spending in this sub-program is $363,000 in the test year. This is in line with recent levels. Note that spending in Electric Distribution Strategy may fluctuate from year to year based on hiring of consultants to conduct projects such as the EJ Regression analysis that was ordered in Case Nos. U-21389 and U-21585.

F. Wildfire Risk Mitigation O&M

Q. Please describe the O&M expenses related to the Wildfire Risk Mitigation Program as shown in Exhibit A-124 (MPK-14), line 53.

A. These are the O&M expenses for the new Wildfire Risk Mitigation work discussed earlier in my direct testimony. The Company is projecting expenses of $512,000 in the test year, as shown in Exhibit A-124 (MPK-14), line 53, column (l). The bridge period expenses represent an annual cost to include spending for wildfire forecasting in the Company's contract with its weather monitoring service, plus expenses to capture LiDAR imagery in high-risk areas of the system.

X. LOSS STUDY

Q. Please describe the Loss Study.

A. The purpose of this study is to allocate system energy and demand losses among the various components of the electric system by calculating a percentage Loss Factor for each component. This information is used to update loss calculations in electric rates. The 2023 Loss Study Report is shown in Exhibit A-131 (MPK-21).

XI. CRITICAL INVENTORY ISSUES

Q. What does your direct testimony address regarding critical inventory issues?

A. In Case No. U-21585, Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United (collectively "MEIU") witness John D. Albers proposed that the Commission direct the Company, in its 2025 electric rate case, to identify hardware items with long lead time and develop and propose a system for maintaining inventory of such equipment. In its final Order in Case No. U-21585, page 42, the Commission agreed with MEIU's proposal and directed the Company to "(1) identify

equipment generally needed for DER and EV interconnections, such as transformers, that currently have a long lead time for procurement, and (2) propose a plan for maintaining an adequate inventory of that equipment to support future development."

Q. What has the Company found regarding common inventory types necessary for interconnecting DERs and EV charging infrastructure?

A. In preparing my testimony, I consulted with the Company's internal subject matter experts on DER interconnections and on EV charging infrastructure. We determined that common inventory types can be grouped into several illustrative categories for both DERs and EV charging infrastructure. In Figure 53 below, I am listing these categories of equipment. This represents the Company's identification of hardware items relevant for DERs and EV charging infrastructure. The figure also indicates, for each category of equipment: a) whether or not the Company has a long-term demand plan forecast of likely needs; b) whether or not the Company has identified multiple suppliers to provide redundancy; and c) whether or not the Company has a long-term contract of at least three to five years' duration with at least one supplier.

FIGURE 53
CRITICAL INVENTORY FOR DERS AND EV CHARGING INFRASTRUCTURE

Group	Equipment Category	Demand Plan?	Redundant Supply?	Long-Term Contract?
DER	Class 2 Poles	Yes	Yes	Yes
	Class 3 Pole	Yes	Yes	Yes
	Class 4 Poles	Yes	Yes	Yes
	Overhead Cable	Yes	Yes	Yes
	Overhead Transformer	Yes	Yes	Yes
	Pole Top Hardware	Yes	Yes	Yes
	Reclosers	Yes	Yes	Yes
	Switches	Yes	In Process	In Process
	Underground Cable	Yes	Yes	Yes
	Underground Hardware	Yes	Yes	Yes
EVs	Class 2 Poles	Yes	Yes	Yes
	Class 3 Poles	Yes	Yes	Yes
	Overhead Cable	Yes	Yes	Yes
	Pole Top Hardware	Yes	Yes	Yes
	Underground Cable	Yes	Yes	Yes
	Underground Hardware	Yes	Yes	Yes
	3-PHASE Transformers	Yes	Yes	Yes

Q. How does the Company plan to ensure that it has adequate supply of these equipment types to meet demand?

A. As indicated in Figure 53 above, the Company has a forecast of expected demand for each category of equipment critical to interconnecting DERs and EV charging infrastructure.

For every category, the Company already has multiple suppliers available, and will have long-term contracts with each supplier by the end of the year to ensure an adequate supply is available. These three components of supply chain planning—making a demand plan, securing multiple suppliers, and establishing long-term contracts—represent the Company's three-prong approach to its supply chain strategy. This is an industry standard approach to addressing critical inventory. The Company expects that, by following this

three-prong approach, it will be well-positioned to meet the needs of interconnecting DERs and EV charging infrastructure.

XII. AMI METRICS

Q. Please explain the requirement to include value-focused AMI metrics and elements in electric rate case filings.

A. The Commission's March 1, 2024 Order in Case No. U-21389 stated:

> As set forth in this order, and in lieu of the continued provision of future advanced metering infrastructure business case updates, Consumers Energy Company and the Commission Staff shall meet as soon as reasonably possible after the date of this order to coordinate on appropriate value-focused advanced metering infrastructure metrics and elements for the company to include in its future rate case filings.

Q. Please explain how the Company is complying with this requirement.

A. The Company met with Staff on March 25, 2024, April 11, 2024, and April 23, 2024, to coordinate appropriate value-focused AMI metrics and elements for the Company to include in its future rate case filings. During those meetings, Staff provided feedback into proposed AMI metrics and elements. The value-focused AMI metrics and elements that have currently resulted from the coordination between Staff and the Company are included in Exhibit A-133 (MPK-23).

XIII. AMI Opt-out Charges

Q. Please explain the requirement to update the AMI Opt-out Charges.

A. In Case No. U-21585, the MPSC Staff recommended the Company re-evaluate AMI Opt-out Charges and rates before the next rate case to ensure that they reflect the cost of service. In its final Order in Case No. U-21585, the Commission agreed and directed the Company to undertake this update for inclusion in the instant case.

Q. Please provide an overview of the AMI Opt-out Charges.

A. The AMI Opt-out Charges are intended for customers who elect to have a non-transmitting meter. By selecting this option, the customer agrees to cost-based up-front and ongoing monthly charges.

Q. What is included in the Upfront Charge?

A. The one-time fee includes the costs associated with replacing the existing AMI meter at a customer's site with a legacy non-transmitting meter.

These upfront costs include:

- Replace Existing Smart Meter with Legacy Non-transmitting Meter – Costs associated with manually removing and replacing a smart meter with a legacy meter.
- Smart Meter Deployment Exceptions Process - Systems Cost – Costs associated with the exceptions process for manual metering including a highly customized systems solution used exclusively for non-transmitting meters.
- Customer Support – Costs associated with responding to customer inquiries about the non-standard metering alternatives, initiating the billing of up-front and ongoing monthly charges, and initiating service requests for meter exchanges when needed.
- Restore Premise to Standard metering – Costs associated with the manual meter exchange from a smart meter to a non-transmitting meter and the potential exchange back to a smart meter in the future.
- Turn on/off – Costs associated with removing a smart meter from the system and adding a non-transmitting meter to the location.

Q. What is included in the Monthly Meter Charge?

A. The monthly charge for opting out of an AMI smart meter includes the costs associated with manual inspections and readings of the meters as well as ongoing non-transmitting meter costs.

These ongoing costs include:

- Meter Reading – Costs associated with reading non-AMI smart meters each month.
- Meter Testing Program for Legacy Meters – Costs associated with the regular testing of manual meters deployed in the field, roughly 6% of deployed non-transmitting meters are tested every year.
- Re-read order – Costs associated with re-reading the manual read at the meter. This process occurs when a manual read was done and the data received identified a discrepancy or error. This can also be requested by the customer.
- Monitoring, Tracking and correcting accounts – Ongoing corrections, troubleshooting, and manual adjustments to non-transmitting meter accounts.
- Non-transmitting Meter Retention – Costs associated with the meter retention program which manually removes, returns, and tests approximately 15% of manual meters yearly.
- Meter Reader Handheld Device Purchases – Cost of purchasing, replacing, and updating handheld meter reading devices used for manual meter reads, done on a four-year cycle.
- Net of AMI and Legacy capital costs – The difference between AMI capital costs and maintenance costs and Legacy capital costs.

Q. What is the Company proposing for AMI Opt-Out Charges?

A. As shown in Exhibit A-136 (MPK-26), the Company is proposing to increase AMI Opt-out Charges to:

- Upfront Charge to replace an existing AMI meter with a Legacy Non-transmitting Meter: $216.22 one-time fee as shown on Line 7 of Exhibit A-136 (MPK-26)
- Monthly Charge: $3.09/month as shown on Line 7 of Exhibit A-136 (MPK-26)

Q. How do the proposed charges compare to the current AMI Opt-out Charges?

A. Figure 54 shows the current AMI Opt-out Charges compared to the proposed charges.

FIGURE 54
CURRENT COMPARED TO PROPOSED OPT OUT CHARGES

Opt Out Charge	Current	Proposed
Up Front Charge	$123.91	$216.22
Monthly Charge	$3.00	$3.09

XIV. SUMMARY

Q. Please summarize your testimony.

A. In this testimony, I have provided an overview of the Company's electric distribution system, including detailed information on the system's recent reliability, and the Company's plan to improve that reliability over the coming years.

I have explained how the Company developed its Reliability Roadmap, and how the plan provided in the Reliability Roadmap will increase investment in the distribution system to improve reliability for customers in the face of increasingly severe weather.

The Company's distribution investments will adhere to the four objectives defined in the Reliability Roadmap, going beyond reliability to ensure safety and security for employees and the public; ensure an equitable grid; and keep costs affordable for customers. By following this strategy, the Company has developed the detailed capital and O&M spending plans outlined in this testimony and the direct testimony of Company witnesses Partlan, Hayward, and McPhail.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

MICHAEL P. KELLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Michael P. Kelly, and my business address is 1945 West Parnall Road, Jackson, Michigan, 49201.

Q. Are you the same Michael P. Kelly who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission Staff ("Staff") witnesses Anna N. Schiller, Nicholas M. Evans, Jacob G. Martus, Hunter Hansen, and Ally Durfee; Attorney General witness Sebastian Coppola; Association of Businesses Advocating Tarff Equity ("ABATE") witnesses Colin T. Fitzhenry and Jessica A. York; Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar (collectively, the "Clean Energy Organizations" or "CEO") witnesses Boratha Tan, Lee Shaver, and William D. Kenworthy; Citizen Utility Board of Michigan ("CUB") witness Richard J. Bunch; Michigan Environmental Council, Natural Resources Defense Council ("NRDC"), Sierra Club, and CUB ("MNSC") witness Caroline Palmer; Great Lakes Renewable Energy Association ("GLREA") witness Richard Boehnke; Urban Core Collective ("UCC") witness Sergio Cira-Reyes; Michigan Electric Transmission Company ("METC") witness Michael Fleck; and Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United ("MEIU") witness John D. Albers.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-219 (MPK-29)	Actual and Forecasted 2025 Capital and O&M Spending;
Exhibit A-220 (MPK-30)	Audit Response 21870-SA-CE-248;
Exhibit A-221 (MPK-31)	Discovery Response 21870-AG-CE-0514; and
Exhibit A-222 (MPK-32)	Discovery Response 21870-AG-CE-0453.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please explain Exhibit A-219 (MPK-29).

A. Multiple parties to this case have analyzed the Company's projected capital and operating and maintenance ("O&M") spending based on the Company's actual year-to-date spending through June 2025, and a number of proposed disallowances are tied to this. Each individual disallowance is addressed by Company witness Jennifer M. Partlan, Company witness Megan L. Hayward, or myself. Exhibit A-219 (MPK-29) provides the Company's year-to-date spending for the contested programs through September 2025, with the forecast through the remainder of the year, in order to provide an updated picture of the Company's 2025 spending.

I. REBUTTAL OF STAFF WITNESS SCHILLER

Q. What is Ms. Schiller's position on alignment between the instant case and the Distribution System Plan ("DSP")?

A. Per the Commission's July 10, 2025 Order in Case No. U-20147 ("July 10 Order"), utility five-year distribution plans will use the standard descriptor Distribution System Plan ("DSP") going forward. To date, the Company has used the terms Electric Distribution Infrastructure Investment Plan ("EDIIP") and Reliability Roadmap. The Company plans

to use the DSP moniker on a go-forward basis, although the three terms – EDIIP, Reliability Roadmap, and DSP – can continue to be understood as interchangeable.

After reviewing the Company's DSP history since 2023, Ms. Schiller concludes on page 9 of her direct testimony that the revised version of the Company's current DSP, filed in the instant case as Exhibit A-129 (MPK-19), either was not necessary under the terms of the July 10 Order or should not have been filed at all. She allows that the Company filed the instant case before the July 10 Order was issued and was following the best guidance available at the time, but states that the Company should not file DSP revisions as part of future rate cases unless warranted by "significant" changes to strategy or misalignments between the rate case and the DSP.

Q. How do you respond to this position?

A. The Company fully intends to comply with all provisions of the July 10 Order, including when DSP revisions in rate cases are warranted. I will note that, contrary to the statement on page 10, line 2, of Ms. Schiller's testimony, the Company's next DSP will be filed in 2026.

Q. What else does Ms. Schiller say about DSP/rate case alignment?

A. On pages 10 and 11 of her direct testimony, Ms. Schiller notes that the Company has changed the names and contents of various programs and sub-programs across multiple rate cases, and between the Company's DSP and rate cases. She cites the movement of Automation Transfer Recloser ("ATR") Loops among different spending areas, and the changes related to breaking up the High Voltage Distribution ("HVD") Lines and Substations Rehabilitation sub-program. She acknowledges that some changes are necessary for the Company's business needs, but states on page 13 that "reasonable and

prudent costs should be categorized and similarly trackable between any DSP submitted by the Company and any rate case which uses such DSP to justify cost recovery."

Q. How do you respond to this argument?

A. Ms. Schiller's point is well-taken. In its 2026 DSP, the Company will endeavor to present planned investments in a format that allow for easier comparison between the DSP and how costs are presented in rate cases.

Q. What arguments does Ms. Schiller make about the outcomes of the audit by Liberty Consulting Group ("Liberty") in Case No. U-21305?

A. Beginning on page 14 of her direct testimony, Ms. Schiller begins discussing the Commission's July 12, 2025 Order in Case No. U-21305 related to the Liberty audit, and discusses the audit in general, especially regarding the Company's assessment of its reliability history relative to Liberty's assessment; the suitability of the Company's modeling that projects future System Average Interruption Duration Index ("SAIDI") based on levels of investment; and the Company's consideration of alternate glidepaths for improving SAIDI based on Liberty's recommendations.

Q. What is Ms. Schiller's position regarding whether the Company has been improving its reliability?

A. Beginning on page 16 of her direct testimony, Ms. Schiller argues that Figure 6 in my direct testimony is misleading. I explained in my direct testimony why Figure 6 illustrated recent improvement in reliability performance. Ms. Schiller avers that the Company's use of a five-year rolling average can obscure other trends, and notes that with a rolling average the line lags behind current data. She then presents her own Figure 1, which fits a linear regression to the Company's SAIDI excluding Major Event Days ("MEDs") from 2014

through 2024, and notes that it shows almost flat SAIDI over that time period. She contends that this illustrates that the Company's reliability has in fact not improved.

Q. Do you agree with this assessment?

A. No. Ms. Schiller's Figure 1 is essentially the same as Liberty's statement that if you use 2014 as a baseline, then reliability is flat over the course of a decade. I alluded to this on page 25, lines 13 through 16, of my direct testimony. One major issue with Liberty's, and with Ms. Schiller's, analysis is that 2014 is an arbitrary date to use for a baseline. Admittedly, some date much be chosen for the start of an analysis, but using 2015 or 2016, which had higher SAIDI results than 2014, would change the shape of the line in Ms. Schiller's Figure 1, as would using 2013 (when SAIDI excluding MEDs was 212) or 2011 (when it was 297). Ms. Schiller acknowledges on page 18, lines 8-9, that 2014 was a particularly good year for SAIDI when compared to adjacent years. I mention in my direct testimony that I used a rolling average to smooth out annual variability and to reduce the arbitrariness of which dates to use. Ms. Schiller suggests at page 17 of her direct testimony that using 10 years of data instead of five years mitigates this, but that is only partially true. Using a linear regression over 10 years may result in less variability than if a linear regression was done over just five years, but a linear regression such as that used by Ms. Schiller over any duration will not address annual variability in the same way that a rolling average does. A rolling average is better for identifying true trends over multiple years. I would further note that using a rolling average means that my Figure 6 actually incorporates 15 years of data, since it indirectly accounts for SAIDI going back to 2009.

Figure 6 in my direct testimony illustrates that reliability has improved since 2021, which was around the time that the Company's investments from its 2018 EDIIP were first

beginning to really impact the system. Notwithstanding any reliability trends from the 2010s, the Company's reliability in the current decade has clearly improved.

Q. What is Ms. Schiller's position on whether the Company effectively considered seven-year and 10-year glidepaths for SAIDI improvement in addition to a five-year glidepath?

A. On page 18 of her direct testimony, Ms. Schiller states that the Company did not "meaningfully examine" extended glidepaths, but simply adjusted its modeling to cover long timeframes. She explains several objections that she has to the Company's modeling, which I will address below. After describing these modeling objections, she returns to the alternate glidepaths themselves on page 20, stating that the Company's analysis did not consider cost effectiveness, affordability, or rate impacts, and that while the Company complied with the letter of Liberty's recommendations, it did not consider the Commission's Order related to approaching SAIDI in a cost effective manner.

Q. Aside from the modeling concerns, how do you respond to this?

A. It is not clear to me why it would be inappropriate to evaluate alternate glidepaths by adjusting the Company's modeling to target different dates. Indeed, it is not clear what other approach could be appropriate. The Company's model is designed to project a SAIDI performance at a given future date when considering spending inputs. If the Company is modeling a given SAIDI performance by 2029 (then five years into the future), then considering alternate glidepaths necessarily means running that model to show an equivalent performance in 2031 and 2034.

Additionally, as Ms. Schiller notes, the Commission's Order in Case No. U-21305 did not come out until June 12, 2025, which was after the instant case was filed. The

Company, at the time of filing, only had Liberty's report to rely on, and the Company therefore responded to Liberty's recommendation. The Company will certainly comply with the Commission's further direction from its Order in Case No. U-21305 in future filings.

Q. What else does Ms. Schiller say about the Company's comparison of alternate glidepaths?

A. On page 21 of her direct testimony, Ms. Schiller objects to my position (stated on page 40, line 9, through page 41, line 9, of my direct testimony) that the Company must pursue a five-year glidepath because the longer glidepaths would compel the Company to cut specific investment programs entirely or to low levels. Ms. Schiller states that neither Liberty nor the Commission has mandated that particular programs be cut to create the longer glidepaths, and that the Company could explain why certain programs should not be cut.

Q. How do you respond?

A. Ms. Schiller is correct that no such constraints were placed on the development of alternate glidepaths, but that does not mean that the Company would not be effectively constrained. As page 32, Figure 13 of my direct testimony illustrates, significant System Average Interruption Frequency Index ("SAIFI") improvements underpinning the Company's modeled glidepath come from a handful of investment categories (this does not mean other investments do not contribute to reliability – see page 31, lines 12 through 14, of my direct testimony). Given the clear direction from Liberty that Line Clearing should be increased, that cannot be reduced to create longer glidepaths. Security Assessment Repairs address actually failed components on the system and cannot be responsibly deferred. This leaves

Zonal Health Projects, Fractionalization, and ATR Loops as the remaining options for creating a model that delays the achievement of second quartile SAIDI excluding MEDs until later dates. If the Company delayed its glidepath, it would continue to invest in programs that hold SAIDI roughly steady by addressing deterioration, but would not invest as much or at all in certain programs that would improve SAIDI, since the entire purpose of an extended glidepath is to delay reliability improvements to achieve the tradeoff of making fewer capital investments.

Q. Does Ms. Schiller make any other comments about the Company's approach to alternate glidepaths?

A. Yes. On page 22 of her testimony, Ms. Schiller objects to my assertion that the Company should be entitled to invest at levels that would allow it to avoid penalties in the Commission's performance-based ratemaking ("PBR") framework.

Q. How do you respond?

A. The Company understands the Commission's PBR framework as at least a partial guide for targeted reliability improvements. Through its creation of the PBR framework, the Commission has established certain target reliability, backed by financial consequences for utilities. This framework establishes the target reliability levels that the Commission expects the Company at a minimum to pursue.

Q. What does Ms. Schiller say about the Company's modeling of future reliability performance?

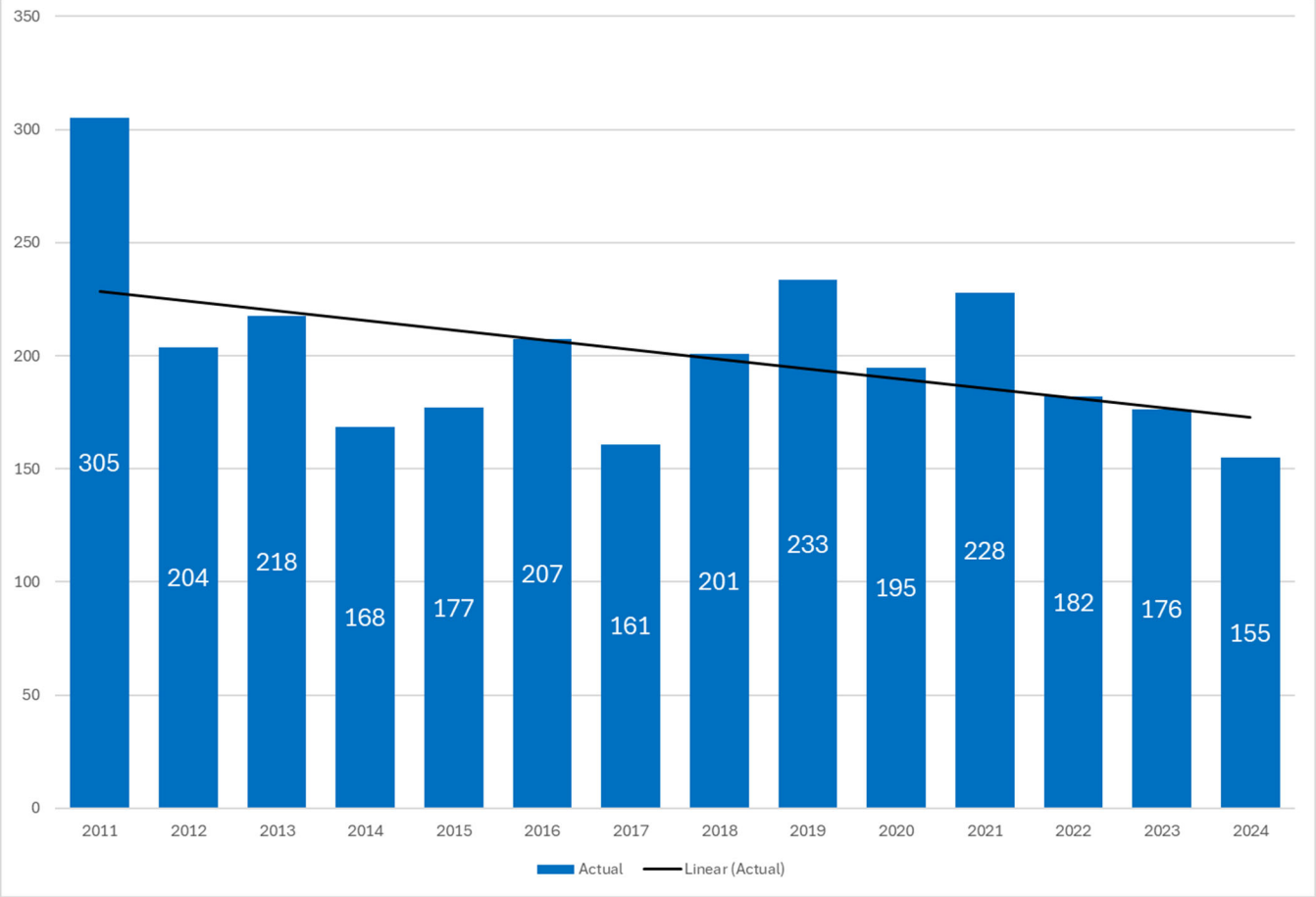
A. On page 19 of her direct testimony, Ms. Schiller criticizes the Company's modeling by saying that it has not been able to predict future reliability for two of the previous four years and that the Company cannot guarantee accuracy. She also states that the model is

flawed because it only considers five years of historical data (she recommends using 10 years) and because it is not weather-normalized in a period where increasingly severe weather is expected. Because of these concerns, she recommends that the Commission require a different modeling method to examine potential extended timelines for SAIDI improvements in the Company's next rate case.

Q. Do you agree with this?

A. No. The Company has been and will continue to make model improvements. While the model in its present form has undergone continued improvements from the version used for the last rate case, its fundamental origins date back to at least the 1990s. It is not realistically possible for the Company to guarantee the accuracy of a predictive model that is impacted by future weather patterns. Factoring in over a decade of system age related deterioration and ever increasingly severe weather, even a relatively flat 2014 to 2024 linear trend would indicate improved system performance, notwithstanding the flaws with only looking at a 2014 to 2024 linear trend as discussed above. The Company believes that the previous five years is more reflective for both present system and weather conditions. If additional years of data are desirable, the Company could look back at 14 years of data and show that annual SAIDI has nearly been cut in half since 2011, as shown in Figure 1 below.

FIGURE 1
SAIDI PERFORMANCE EXCLUDING MEDS, 2011-2024



Additionally, the Company has historically forecasted SAIDI excluding MEDs. By excluding MEDs, the Company is accounting for much of the volatility resulting from weather. Small storms do have an impact on the metric, but more importantly, to accurately normalize weather reporting for day-to-day operations, crisis-mode restoration in the days following catastrophic events needs to be appropriately accounted for when calculating the Company's performance for SAIDI excluding MEDs. Adjusting for such events in calculating SAIDI would likely improve the modeling by eliminating the volatility of these significantly large events and providing a better alignment to actual day-to-day system performance as measured by the SAIDI excluding MED standard.

Finally, in the Company's efforts to continuously improve its modeling capabilities for forecasting future reliability performance, it conducted a review of the regulatory filings of Midwestern peer utilities. In this review the Company found that only one utility, DTE, provided a forecast of future performance for All-weather SAIDI while the others simply discussed past performance. Compared to the Company's modeling of future SAIDI excluding MEDs, All-weather SAIDI, and CEMI performance, it appears that peer utilities share very little information. Therefore, if the Commission finds that the Company's current SAIDI performance model is inaccurate to the extent that it requires a new method to be developed, the Company asks that the MPSC Staff provide publicly available and benchmarkable models from electric utility industry peers that have guaranteed forecasted performance as Ms. Shiller deems is necessary for the Company. Furthermore, the Company asks that the Commission provide the Company with at least three years to test and validate an alternative methodology's precision and accuracy.

II. REBUTTAL OF STAFF WITNESS EVANS

Q. What is Mr. Evans' recommendation regarding the Company's Distribution Deferral Mechanism?

A. On page 8 of his direct testimony, Mr. Evans concludes that the Company's actual capital spending as part of the Distribution Deferral Mechanism between March 1, 2024 and February 28, 2025, was reasonable and prudent. Because of this, on page 9 of his direct testimony he recommends that the Company be permitted to continue using the deferral mechanism as requested in the instant case. Mr. Evans recommends four conditions to this approval, and notes in footnote 1 of his testimony that they are substantively identical to those approved by the Commission in Case No. U-21585.

Q. Do you agree with this recommendation?

A. Yes. The Company appreciates Staff's continued support of the deferral mechanism, and finds that the conditions continue to be reasonable.

Q. What is Mr. Evans' recommendation regarding the Company's Investment Recovery Mechanism ("IRM")?

A. On page 11 of his direct testimony, Mr. Evans indicates that Staff supports the Company's proposed two-year extension of its IRM, but with three changes. First, he recommends that the amount for the Repetitive Outages sub-program should be adjusted to reflect proposed disallowances made by Staff witness Ryan Boutet. Second, he recommends that investment related to the Vulnerable Communities Resiliency Plan ("VCRP") be removed from the IRM and placed into rate base. Third, he recommends that the rate of return associated with the IRM surcharge should be lower than the pretax rate of return, but no lower than the short-term debt rate.

Q. Do you agree with these recommendations?

A. No. Company witness Partlan explains in her direct testimony why Mr. Boutet's proposed disallowance for Repetitive Outages should not be adopted by the Commission. Company witness Heidi J. Myers addresses Mr. Evans' recommendation related to the rate of return.

As to the VCRP, Mr. Evans agrees, on page 12 of his direct testimony, that the Company should be investing in the VCRP, but states that recovery of these investments does not need to occur in the IRM. It is not clear why Mr. Evans reaches this conclusion. The Company proposed to include the VCRP in the IRM precisely because it is important to invest in Environmental Justice ("EJ") communities; the IRM provides a backstop to ensure that the investments are made, with the Company required to provide refunds if the

Company does not make the full investments. Furthermore, the Commission's Order in Case No. U-21389, approving the initial IRM, made clear that the Company should show how the IRM promotes system equity. The Company believes that including the VCRP in the IRM provides one clear mechanism for doing this.

III. REBUTTAL OF STAFF WITNESS MARTUS

Q. What is Mr. Martus' recommendation regarding the Company's proposed regulatory deferral mechanism for the Staking and Locating O&M sub-program?

A. As stated on pages 5 and 6 of his direct testimony, Mr. Martus states that Staff supports the Company's proposal, but he recommends that the mechanism only cover fluctuations stemming from the variability in staking volume. He recommends that the recovery and refund amounts for the mechanism be set by an equation that he provides and explains. He states that this recommendation is very similar to what Staff recommended for the Company's corresponding proposal in its most recent gas rate case, Case No. U-21806.

Q. Do you agree with this recommendation?

A. Partially. The Company does not oppose the principle that the deferral mechanism should be limited to fluctuations based on staking volume. Mr. Martus' "Equation 1" is a reasonable means of calculating what this fluctuation is in a future period. However, it is not appropriate to cap the recovery or refund amounts based on historical volume fluctuations, as Mr. Martus proposes. The purpose of the deferral mechanism is to address future uncertainty about staking volumes, and that uncertainty is due in large part to potential variability tied to new rural broadband programs. Because the future variability is tied to this new development, there should be no cap indexed to historical variability that may no longer apply. Furthermore, the Company's actual year-to-date staking volume through September 2025 is 411,518, and the Company is on track to have a 2025 staking

volume of over 520,000, an upward variation well in excess of 3.77%[1], further showing that Mr. Martus' proposed cap on deferral recovery is out of date. Therefore, Mr. Martus' "Equation 2" and "Equation 3" should not be used.

If the Commission decides that it wants some kind of cap on recovery and refund in the deferral mechanism, it should at least be symmetrical, such as +/- 10% in each direction. It is not reasonable to create an unbalanced mechanism with nearly three times as much risk as potential benefit to the Company, as Mr. Martus proposes.

IV. REBUTTAL OF STAFF WITNESS HANSEN

Q. What does Mr. Hansen recommend regarding the Company's proposed upfront charge for advanced metering infrastructure ("AMI") opt-outs?

A. On page 6 of his direct testimony, Mr. Hansen reviews information that the Company provided to Staff in audit, and calculates that the Company's proposed upfront charge of $216.22 should be reduced to $168.07 based on that audit information.

Q. Do you agree with this recommendation?

A. Yes. The information that the Company provided in audit supports Mr. Hansen's calculations.

Q. What does Mr. Hansen recommend regarding the Company's proposed monthly charge for AMI opt-outs?

A. On pages 6 and 7 of his direct testimony, Mr. Hansen states that the Company's breakdown of costs to support the proposed $3.09 monthly charge do not accurately reflect the Company's monthly cost of reading non-AMI electric meters. He argues that most of the costs seem to actually apply to reading Automated Meter Reading ("AMR") gas meters,

[1] To be specific, the Company's staking volume for January-September 2024 was 335,913, meaning the January-September 2025 actuals are a 22.5% year-over-year increase.

and therefore they do not support a cost-of-service basis for the Company's proposed charge. He recommends that the Commission reject the proposed charge, and that the Company should begin separately tracking the costs of reading non-AMI electric meters so it can propose a better cost-of-service based charge in the future.

Q. Do you agree with this recommendation?

A. No. For one thing, it is not clear whether Mr. Hansen is arguing that there should be no monthly charge at all until the Company performs this new analysis, or if the existing monthly charge should remain in effect until that time. If he intends the former, this is not reasonable. The existing charge is already in effect and should not be completely eliminated until a replacement is available. The monthly cost of reading non-AMI electric meters is clearly not $0.00, so it would be unreasonable for the Commission to effectively set the monthly charge at that level.

Beyond that, the Company provided an alternative analysis in alignment with the methodology used in prior cases, based on an allocation of labor and associated overhead for supervision, support, and vehicle costs for non-transmitting meters in Staff Audit response 21870-SA-CE-248, which is being provided as Exhibit A-220 (MPK-30). This analysis supported a charge of $12.61/meter/month. While the Company is not proposing a $12.61 monthly charge at this time, this illustrates that it would not be reasonable for there to be no monthly charge. As to separately tracking the costs of reading non-AMI electric meters, Consumers Energy can look into that possibility. I will note that there are challenges attempting to separately track these costs because the Company does not have a dedicated electric meter reader team that only reads non-AMI meters.

V. REBUTTAL OF STAFF WITNESS DURFEE

Q. What is Ms. Durfee's general approach to the Company's Electric Distribution O&M spending?

A. Ms. Durfee reviewed the Company's year-to-date spending through June 2025 and has interpreted that to represent the amount that the Company is likely to spending going forward. In each case, she assumes a linear monthly spending to project likely test year spending. I will address each sub-program individually, but it is important to note that many programs often do not follow a linear monthly spend, and it would be incorrect to base all projections only on a single six-month period.

Q. What is Ms. Durfee's recommendation regarding the Low Voltage Distribution ("LVD") Lines Reliability O&M sub-program?

A. On page 15 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $754,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a $7.222 million disallowance for the test year, based on the Company staying at these spending levels.

Q. Do you agree with this recommendation?

A. No. The Company constrained its O&M spending in the first half of 2025 following the catastrophic ice storm and subsequent severe weather experienced in March and April of 2025. The severe weather caused widespread damage to the Company's electric grid, resulting in the Company requesting Commission approval to defer O&M expenses associated with the storm even for recovery in a future case. The Commission granted the Company the accounting authority to defer these excess expenses on June 12, 2025 in Case No. U-21914, which has allowed the Company to once again focus on additional O&M-

related activities. Exhibit A-219 (MPK-29), line 1, shows how LVD Lines Reliability O&M was constrained in the first half of 2025, but how it has increased since then. The Company is fully planning to spend at the projected amounts in the test year.

Q. What is Ms. Durfee's recommendation regarding the HVD Lines Reliability O&M sub-program?

A. On page 16 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $68,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a disallowance of $821,000 for the test year, based on the Company staying at these spending levels.

Q. Do you agree with this recommendation?

A. No. Ms. Durfee is correct that the Company's filed test year position for HVD Lines Reliability O&M is too high. However, the Company's five-year history in this sub-program, as shown in Exhibit A-124 (MPK-14), line 5, shows that the Company has consistently spent at higher levels than Ms. Durfee is recommending here. The Company's test year spending level should be set at the five-year average of $214,000. See my rebuttal to Attorney General witness Coppola for further discussion of this topic.

Q. What is Ms. Durfee's recommendation regarding the LVD Substations Reliability O&M sub-program?

A. On page 17 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $3,821,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026,

and a $1.54 million disallowance for the test year, based on the Company staying at these spending levels.

Q. Do you agree with this recommendation?

A. No. The LVD Substations Reliability O&M sub-program is an example of an area where spending is not linear during the year. In a typical year, spending in this sub-program is lower in the winter and spring but ramps up in the summer and fall. The Company's current year-to-date spending is shown in Exhibit A-219 (MPK-29), line 2. As shown, the Company spent as much in the third quarter of the year as it did in the first half of the year combined, and the Company is on track to spend significantly closer to its projected amount. Accordingly, the projected test year is a reasonable projection the Company's expected spending.

Q. What is Ms. Durfee's recommendation regarding the HVD Lines Demand O&M sub-program?

A. On page 18 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $512,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a $2.451 million disallowance for the test year, based on the Company staying at these spending levels.

Q. Do you agree with this recommendation?

A. No. The workforce that completes HVD Lines Demand O&M work is also engaged in HVD Lines Reliability capital projects, meaning the Company must balance between the two categories of work. In the test year in the instant case, the Company is projecting a modest increase in HVD Lines Reliability capital work. This will allow for more balance

in the overall workplan for this workforce, which will enable the Company to complete more HVD Lines Demand O&M work in 2026 and 2027. The Company has already identified enough O&M work to account for the full test year projection.

Q. What is Ms. Durfee's recommendation regarding the Staking and Locating O&M sub-program?

A. On page 19 of her direct testimony, Ms. Durfee argues that it is inappropriate for the Company to use MISS DIG's projection of 7% statewide growth in staking volumes. She argues that the Company's own recent actual staking requests support an annual growth rate of 2.28%. She recommends recalculating the Company's projected staking volumes based on this revised rate, and calculates a $1.517 million disallowance based on the difference.

Q. Do you agree with this recommendation?

A. No. Simply looking at the Company's recent actual history does not paint a complete picture. As stated on page 150, line 15, through page 151, line 2, of my direct testimony, the Company anticipates greater than normal growth in staking requests due to expansion of rural broadband infrastructure (note that Company witness Partlan's direct testimony documents the scale of this activity, and the large impact that this will have on the Company's LVD system). On page 151, line 5, through page 152, line 16, of my direct testimony, I explain this rural broadband growth and its impact on staking volumes is what led the Company to propose a deferral mechanism for this O&M sub-program. The deferral mechanism provides a way to refund customers if staking volumes end up lower than projected for any reason. Since Staff supports this deferral mechanism, as outlined by

Mr. Martus, Staff should be confident that customers will be protected in the event that staking volumes are lower than projected.

Additionally, as noted above in my response to Mr. Martus, the Company's year-to-date staking volume through September is 411,538 and the Company is on track to have a staking volume in 2025 of over 520,000, indicating that staking growth is very robust. As noted on page 150 of my direct testimony, Figure 50, that amount would be higher than any of the annual amounts originally projected through 2027 in this case.

Q. What is Ms. Durfee's recommendation regarding the Alma Equipment Repair O&M sub-program?

A. On page 20 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $358,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a $201,000 disallowance for the test year, based on the Company staying at these spending levels.

Q. Do you agree with this recommendation?

A. No. As stated above, it is incorrect to only consider a single six-month period when assessing likely spending levels in the test year. The Company's five-year historical average is a better approximation of what the Company is capable of spending in a given year, since it accounts for some variation that can occur on an annual basis and because it is a longer track record of data. The Company's five-year average for Alma Equipment Repair O&M is $530,000, and the Company's test year projection in this case is effectively in line with that when accounting for inflation. The Commission should approve the Company's projected spending level.

Q. What is Ms. Durfee's recommendation regarding the Tools O&M sub-program?

A. On page 21 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $896,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a $1.057 million disallowance for the test year, based on the Company staying at these levels.

Q. Do you agree with this recommendation?

A. No. This is another sub-program where it is more appropriate to consider the Company's five-year average rather than just looking at one six-month period. The Company's five-year average for the Tools O&M sub-program is $1,634,000. The Company's projected test year spending is essentially in line with this level, and the Commission should approve the Company's projection.

Q. What is Ms. Durfee's recommendation regarding the Underground Workforce O&M sub-program?

A. On page 22 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $584,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a $1.633 million disallowance for the test year, based on the Company staying at these levels.

Q. Do you agree with this recommendation?

A. No. Underground Workforce O&M is a sub-program where it is particularly inappropriate to assume a linear monthly spending rate based on the first half of 2025. The Company was not performing a significant amount of undergrounding work during this time period.

However, in the test year the Company is planning to complete 50 miles of overhead to underground ("OHUG") conversions, a workplan that Staff is supporting in this case. This work in the test year will lead to higher O&M costs for the underground workforce than was incurred in the first half of 2025, and the Commission should approve the Company's projection.

VI. REBUTTAL OF ATTORNEY GENERAL WITNESS COPPOLA

Q. What is Mr. Coppola's recommendation regarding the Company's proposed OHUG conversion work?

A. Mr. Coppola begins his discussion of OHUG on page 31 of his direct testimony. He states that the Company's changing of selection criteria indicates that it is "still struggling to find an effective approach that adequately justifies undertaking" OHUG work. Company witness Partlan addresses this issue in her direct testimony. Mr. Coppola makes several other arguments that I will address.

Mr. Coppola states that my net present value analysis of OHUG shows that it is the most expensive option compared to other alternatives when using the utility cost test ("UCT"). He states that the Company's selection criteria set relatively low thresholds by which thousands of overhead line miles could be selected. He states that the Company has not conducted a separate benefit-cost analysis for each individual project to determine if it is economic compared to other potential solutions. He argues that the Company's OHUG pilot showed average costs of $443,079 per line mile, and notes that individual projects sometimes cost more than that, arguing that this further indicates a need for individual project benefit cost analyses. Finally, he states that my net present value analysis using the societal cost test ("SCT"), showing that OHUG is the most economic option, should be disregarded. He contends that the SCT analysis assumes an equal value for each minute

of an outage, when in reality some customers can sustain outages for many hours without incurring any costs, and that customers really only accrue costs to themselves when outages last a day or longer.

Q. How do you respond to these critiques?

A. As I also discuss later in my rebuttal to ABATE witness Fitzhenry, Figure 26 in my direct testimony does show that OHUG is more expensive than alternatives at scale. However, OHUG is only 2% more expensive, on average, and page 66, lines 9 through 13, of my direct testimony indicate that OHUG provides at least a 90% reliability improvement because the threat of trees is almost completely eliminated. This level of reliability improvement is much greater than that offered by alternatives. Combined with the fact that OHUG is only very marginally more expensive, this still represents good value for the money.

Although Mr. Coppola takes some issue with the potentially large number of overhead line miles that could theoretically be eligible for OHUG projects, it is important to emphasize that, in the instant case, the Company is only seeking approval for 50 miles of work. And on page 35 of his direct testimony, Mr. Coppola makes reference to the Commission's June 12, 2025 Order in Case No. U-21305, which called for "additional evidence, including *a* BCA"[2] following the completion of the pilot approved in Case No. U-21389 "to fully evaluate the proposed undergrounding and how it compares with other potential pathways to improved reliability performance." This language indicates that the Commission does not expect separate benefit cost analyses for each individual project, but only one analysis covering OHUG as a program, which I have provided in my net present value analyses in

[2] See page 27 of the June 12, 2025 Order.

the instant case. Indeed, the Company has complied with all relevant direction given by the Commission on this issue in Case No. U-21305.

As to Mr. Coppola's dismissal of the SCT, it may be the case that some customers can endure certain duration outages with comparatively little inconvenience. However, the Company's distribution strategy is not based on identifying the maximum outage duration that customers can endure and allowing customers to experience that. Many customers, particularly in vulnerable communities, cannot endure many hours of outages without facing material impacts. And the Company does not believe that any customers should be consigned to outages lasting a day or longer before those outages are worth preventing.

Q. What is Mr. Coppola's overall recommendation regarding OHUG work?

A. On page 35 of his direct testimony, Mr. Coppola recommends that the Commission should fully disallow all bridge period ($1.25 million) and test year ($20 million) costs for OHUG. For all of the reasons given above, Mr. Coppola's recommendation should be rejected. The Company has shown that OHUG is a competitive (using the UCT) or even superior (using the SCT) economic alternative for improving reliability and resiliency. Additionally, the $1,250,000 for OHUG in the bridge period is simply carry-over of pilot costs for work completed in the bridge period that was already approved in Case No. U-21389, and those dollars should not be disallowed in any case.

Q. What is Mr. Coppola's recommendation regarding the EGLE-MIEJ Undergrounding Secondary and Services projects?

A. On page 36 of his direct testimony, Mr. Coppola observes that these projects are still in the preliminary phases of development, and he recommends that the full $4,118,000 proposed for the bridge period and test year be disallowed.

Q. Do you agree with this recommendation?

A. The Company will not contest this proposed reduction in capital expenditures for these projects. However, if the $4,118,000 is removed from the bridge period and test year, then the corresponding grant amounts also need to be removed from the totals reflected in Exhibit A-12 (MPK-1), Schedule B-5.7, line 9. This would reduce those negative numbers by $1,349,000 for the bridge period and $2,698,000 for the test year as shown in Exhibit A-121 (MPK-11) line 1 - 2024 40101(d) Formula Grants to States and Indian Tribes - Investment in DACs for Reliability and Readiness for Electrification, in effect putting that amount back into the Company's rate base for those periods.

Q. What are Mr. Coppola's recommendations regarding the Staking and Locating O&M sub-program?

A. He makes two recommendations. On page 167 of his direct testimony, Mr. Coppola objects to the Company's use of a 7% growth rate. He makes a substantively similar argument to that made by Ms. Durfee on this issue, and recommends that a 2% rate be used instead, with a corresponding disallowance of $866,000 for the lower projected volumes.

Q. Do you agree with this recommendation?

A. No. As I already discussed in my rebuttal to Ms. Durfee, simply using historical actual levels does not paint a complete picture, the deferral mechanism provides protection for customers, and the Company's staking growth in 2025 supports the projected growth rate that the Company used in this case.

Q. What is Mr. Coppola's second recommendation?

A. On pages 167 and 168 of his direct testimony, Mr. Coppola objects to the Company's transition to a dedicated contractor model for staking and locating work, instead of a shared

contractor model. He argues that the Company did not demonstrate that performance issues existed across the Company's service territory. Based on this, he recommends a substantial disallowance of $5.872 million based on the incremental cost of the dedicated model.

Q. Do you agree with this recommendation?

A. No. It is important to note that the Company operates a single Staking and Locating program for both its electric and gas businesses, meaning the Company will generally have one set of practices for both. Especially in the Company's combination territory with both gas and electric customers, it would not be practical to use a dedicated contractor model for gas customers and a shared model for electric customers, particularly since the Company will only "roll one truck" to mark gas and electric infrastructure at a given site. With that in mind, the Company already proposed the dedicated contractor model in its most recent gas rate case, Case No. U-21806. In that case, Mr. Coppola raised various objections to the dedicated contractor model, and Company witness James P. Pnacek provided detailed rebuttal to Mr. Coppola's arguments.

In the instant case, Mr. Coppola argues that the Company has not supported going to a dedicated contractor model. But I provided substantial detail in support of the Company's strategy on page 146, line 18, through page 149, line 2, of my direct testimony. Mr. Coppola does not address or acknowledge this discussion in his direct testimony.

Perhaps the most crucial part of the Company's rebuttal to Mr. Coppola in Case No. U-21806 was the fact that the Company's former shared contractor model contract expired earlier in 2025. When the Company issued a request for proposals for a new contract, which was open to both dedicated and shared contractors, the Company only

received one bid for a shared contractor, and it had a higher unit cost than the dedicated contractor whom the Company selected. In other words, there was no option for the Company to continue using a shared contractor model to save money; going forward, the dedicated contractor model is the most cost effective. As indicated on page 148, line 1, of my direct testimony, the dedicated contractor model is $0.51 less costly on a unit cost basis than the shared contractor option that would have been available.

The Commission approved the Company's dedicated contractor model proposal in Case No. U-21806, and the Commission should reject Mr. Coppola's recommendation in the instant case just as it did in Case No. U-21806. The gas business has transitioned to a dedicated contractor model, with Commission approval, and the electric business should not be required to pursue an alternate approach.

Q. What is Mr. Coppola's recommendation regarding the HVD Lines Demand O&M sub-program?

A. On page 169 of his direct testimony, Mr. Coppola notes that the Company did not propose a large increase to this O&M sub-program's level in Case No. U-21585. He further notes that the Company is on track to underspend on this sub-program in 2025, and he recommends that the test year spending level should be set at the highest actual level incurred by the Company in the last five years.

Q. Do you agree with this recommendation?

A. No. First, Mr. Coppola is incorrect about Case No. U-21585. The Commission's March 21, 2025 Order in that docket, page 276, notes that the Company did in fact identify an increase in identified anomalies that warranted more spending in this sub-program, and on page 277, the Commission approved the Company's projected increase of $2.2 million

in this sub-program. Regarding the proposed disallowance based on spending in 2025, please refer to my rebuttal to Ms. Durfee.

Q. What is Mr. Coppola's recommendation regarding the Service Calls O&M sub-program?

A. On page 170 of his direct testimony, Mr. Coppola agrees with the Company's projected labor cost increase for this sub-program, but does not agree with the projected increase in hours worked. He proposes a disallowance based on tying costs to the five-year average, adjusted for the labor cost increase, resulting in a reduction of $798,000.

Q. Do you agree with this recommendation?

A. No. Although the Company does project a number of work hours for this sub-program, page 159, lines 17 through 22, of my direct testimony, indicates that projected spending is driven by work order volumes. As stated on page 159, line 9, the Company's recent history has involved approximately 33,000 discrete calls per year. Mr. Coppola makes reference to discovery response 21870-AG-CE-0514, which I am providing as Exhibit A-221 (MPK-31). As shown in that response, the Company is on track for 34,855 work orders in the test year, an increase from those historical levels. The response also indicates that work orders are multiplied by an hourly factor to produce a projected amount of work hours, but that different types of work orders can take different amounts of time, meaning work orders and hours may not always be correlated one-for-one.

Q. What is Mr. Coppola's recommendation regarding the LVD Lines Reliability O&M sub-program?

A. On page 172 of his direct testimony, Mr. Coppola notes that the Company is apparently not on track to meet its spending targets for this sub-program in 2025, and he recommends

a test year disallowance of $7.060 million to bring the Company's projection in line with its actual trajectory.

Q. Do you agree with this recommendation?

A. No. Mr. Coppola is making a substantially similar argument to that of Ms. Durfee. Please refer to my rebuttal to her.

Q. What is Mr. Coppola's recommendation regarding the HVD Lines Reliability O&M sub-program?

A. On page 172 of his direct testimony, Mr. Coppola notes that the Company admitted in discovery that its projected test year spending level should be reset to the five-year historic average, which would be a disallowance of $677,000 from the Company's filed position.

Q. Do you agree with this recommendation?

A. Yes. Mr. Coppola's recommendation aligns with the Company's stated revised position in discovery.

Q. What is Mr. Coppola's recommendation regarding the LVD Electric Distribution O&M sub-program?

A. On page 173 of his direct testimony, Mr. Coppola notes that the Company's 2025 spending in this sub-program is not on track to meet projected levels, and he proposes to limit the Company's test year spending to the 2024 actual level, resulting in a test year disallowance of $4.519 million. He further notes that the primary driver of the Company's proposed increase is tied to Grid Automation work, and he states that the "tasks performed in this area have been ongoing for some time" and therefore no increase is needed.

Q. Do you agree with this recommendation?

A. No. The projected increase tied to Grid Automation is not related to ongoing work, and Mr. Coppola does not state how he came to that conclusion or how he defines ongoing work. Because the Company's increase for this sub-program is driven by new Grid Automation work, it is not appropriate to index the spending level to a historical amount.

Q. What is Mr. Coppola's recommendation regarding the Electric Geographic Information System ("GIS") Utility Network Transformation project and the Electric GIS Design Platform Modernization project?

A. On page 90 of his direct testimony, Mr. Coppola argues that these projects are too early in their development for inclusion in rate base, and he recommends that they be disallowed.

Q. How do you respond to this?

A. Company witness Stacy H. Baker provides the primary rebuttal to Mr. Coppola regarding these projects. However, I want to also reemphasize the benefits of these projects for the Company's electric distribution system, as outlined on pages 118 through 122 of my direct testimony.

VII. REBUTTAL OF ABATE WITNESS FITZHENRY

Q. What is Mr. Fitzhenry's assessment of the Company's electric distribution reliability?

A. On pages 4 and 5 of his direct testimony, Mr. Fitzhenry suggests that the Company's 2024 SAIDI excluding MEDs of 155 minutes, compared to a projected 170 minutes, is the basis of the Company's claim that reliability investments are producing improvements.

Q. How do you respond to this characterization?

A. Mr. Fitzhenry references page 29 of my direct testimony to support his interpretation that the Company is claiming that reliability has improved based on 2024 actual results

compared to projections. While that is one piece that supports the Company's assertion, my position that the Company's reliability has been clearly improving is based on the data shown in Figure 6 in my direct testimony. This figure shows that SAIDI has been improving in absolute terms since 2021, that the rolling five-year average has been falling since 2022, and that each individual year beginning in 2022 has been substantially better than the five-year rolling average (see my earlier rebuttal to Ms. Schiller for the discussion as to why this analysis is appropriate). Page 25, lines 13 through 21, of my direct testimony further explains why the Company's analysis is more appropriate than Liberty's approach of simply looking at data from 2014 through 2023.

Q. What other arguments or analysis does Mr. Fitzhenry provide about the Company's reliability?

A. On pages 5 and 6 of his direct testimony, Mr. Fitzhenry states that he has conducted his own analysis to compare the Company's reliability to peer utilities. Using publicly available data, he has compared the Company's SAIDI with and without MEDs to investor-owned utilities in Michigan, Wisconsin, Indiana, and Ohio. Of the 17 utilities considered, Mr. Fitzhenry states that the Company always ranks 12th or worse, with an average rank of 15th. Based on this, he concludes that the Company is at or near the bottom for reliability when compared to peers.

Q. How do you respond?

A. The numbers cited by Mr. Fitzhenry do speak for themselves to some extent, but Mr. Fitzhenry's analysis supposes that other investor-owned utilities in states with land borders with Michigan (and in Michigan itself) are a good comparison group because those utilities face roughly similar weather challenges as the Company. But even if weather were

similar all the way from northern Wisconsin to southern Ohio, which is not necessarily the case, weather is only one part of what makes utilities similar or dissimilar for purposes of comparison. Utilities can have dramatically different systems in terms of square mileage, line mileage, customer density, percentage of system overhead versus underground, prevalence of heavily forested terrain, and various other factors that can have major implications for reliability. In his table CTF-1, Mr. Fitzhenry has included utilities in northern Wisconsin and the Upper Peninsula of Michigan with less than 1% of the Company's customer count and service territories that are exclusively rural areas and small towns. Additionally, Madison Gas & Electric has approximately 60% of its lines underground, making it a poor point of comparison to the Company. He has also included Dayton Power & Light, a utility that primarily serves a large metro area and surrounding areas of open farmland. A more nuanced discussion comparing the Company to peer utilities and accounting for system differences is given on pages 15 and 16 of Exhibit A-129 (MPK-19).

Notwithstanding that caveat, the Company's argument is not that its reliability is good relative to peers today. My direct testimony is very clear about the fact that the Company's SAIDI is even now in the third quartile, and the entire premise of the Reliability Roadmap is to improve the Company's reliability into the second quartile. However, the Company's reliability has improved in recent years relative to its peers, as I discuss on page 26, lines 1 through 9, of my direct testimony. The analysis supporting this was presented in Figures 7 and 8 in my direct testimony, based on the peer groups participating with the Institute of Electrical and Electronics Engineers ("IEEE").

Q. What is Mr. Fitzhenry's analysis regarding outage causes?

A. On pages 6 and 7 of his direct testimony, Mr. Fitzhenry cites information that the Company provided about LVD outage causes from 2022 through 2024, and observes that 52% of outages were due to trees either inside or outside the right of way, with a further 26% of outages caused by weather. Based on this, Mr. Fitzhenry argues that the Company should primarily focus on forestry work as opposed to asset replacement in order to improve reliability.

Q. Do you agree with this assessment?

A. No. I addressed the need for continued capital investments alongside increased line clearing at page 35, line 1, through page 37, line 9 of my direct testimony. Mr. Fitzhenry's direct testimony does not make any reference to this part of my direct testimony, so it is not clear that he has evaluated the Company's rationale for why forestry and capital investments are both important for improving reliability.

It is also important to note that it appears that Mr. Fitzhenry's analysis assumes that any weather-caused outage must have been tree-related, but this is not correct. Weather impacts on the system can cause direct damage to assets even if trees are not involved. For example, straight-line winds or a tornado in the middle of an open field can be strong enough to damage assets without tree contact. Furthermore, some tree-related outages are in part a result of failed assets that have not been hardened to withstand tree impacts; in other words, tree contact may have been the event that initiated an outage, but a hardened system is better able to withstand this initial strike and continue to serve customers.

Q. What else does Mr. Fitzhenry say about the impact of the Company's investments on reliability?

A. On pages 8 and 9 of his direct testimony, Mr. Fitzhenry compares the Company's additions to distribution plant over 2020 through 2024 to the Company's all-weather SAIDI over the same period. While distribution plant has increased, all-weather SAIDI has oscillated between about 500 minutes and 900 minutes. Mr. Fitzhenry accuses the Company of cherry-picking reliability by only focusing on SAIDI excluding MEDs when considering if reliability is improving.

Q. How do you respond to this?

A. The Company is certainly not cherry-picking its data by using SAIDI excluding MEDs. SAIDI excluding MEDs is an IEEE-defined industry standard metric, in widespread use by utilities. As stated on page 107 of my direct testimony, MPSC rules backed by Michigan law direct utilities to consider reliability metrics both including and excluding MEDs, so the use of SAIDI excluding MEDs has clear sanction from the State of Michigan. As stated on page 109 of my direct testimony, the benefit of SAIDI excluding MEDs is that it normalizes performance data for unusually severe weather. This is why the Company has used SAIDI excluding MEDs to evaluate recent improvements in reliability, to separate out fluctuations exclusively created by the severity of weather in a given year. This is also why the Company's distribution planning has been premised on making improvements to SAIDI excluding MEDs, since the metric is more reflective of conditions within the utility's control. (See also page 25, lines 9 through 12, of my direct testimony.) The Company's distribution strategy to date has been focused on improving SAIDI excluding MEDs, and the Company has had success in doing so.

Still, it is not accurate to suggest that the Company ignores SAIDI including MEDs, especially given the Commission's direction to consider both. Pages 110 and 111 of my direct testimony present the Company's 10-year history with that metric; the Company is not ignoring it. While the Company's strategy specifically targets SAIDI excluding MEDs, the Company has been introducing new efforts aimed at reducing SAIDI including MEDs for customers. The Resiliency sub-program is largely focused on this, and reducing major event days was the goal of the Company's IRM when it was proposed in Case No. U-21389. The VCRP is also designed to improve SAIDI including MEDs in EJ communities. The newness of these programs means that their impact on SAIDI including MEDs would not have shown up yet in the data.

Q. What is your overall response to Mr. Fitzhenry's discussion of reliability?

A. Mr. Fitzhenry argues on page 9 of his direct testimony that his analysis indicates that the Commission must view the Company's investment plan with "extreme skepticism." Later in his testimony, he uses his analysis to support proposing substantial disallowances, the specifics of which are rebutted by Company witnesses Partlan and Hayward. However, as I have shown, his analysis has multiple flaws and has not addressed much of the evidence on the record.

Q. What is Mr. Fitzhenry's assessment of the Company's plan for OHUG investments?

A. Mr. Fitzhenry begins assessing the Company's OHUG plan on page 16 of his direct testimony. On page 18, he states that he has concerns about the Company's use of the UCT and SCT to justify the OHUG as an economic option for improving reliability and resiliency. He then makes a number of criticisms about the outcomes of the Company's now-completed OHUG pilot.

Q. What does Mr. Fitzhenry say about the UCT and SCT?

A. While he states that he has concerns about the Company's methodology in these tests, he never clearly states what these concerns are. This makes it difficult to effectively rebut his position. He does indicate, on page 20, line 1, of his direct testimony that the UCT shows that OHUG is the most expensive option. As discussed in my rebuttal to Mr. Coppola, Figure 26 in my direct testimony does show that OHUG is more expensive than alternatives at scale. However, OHUG is only 2% more expensive, and page 66, lines 9 through 13, of my direct testimony indicate that OHUG is expected to provide at least a 90% reliability improvement because the threat of trees is almost completely eliminated. This level of reliability improvement is much greater than that offered by alternatives. Combined with the fact that OHUG is only marginally more expensive, this still represents good value for the money.

The SCT analysis presented in Figure 27 of my direct testimony makes this comparison even more favorable for OHUG. Mr. Fitzhenry's only apparent criticism of the SCT is that it is "speculative," because it values long-term benefits. Mr. Fitzhenry does not provide any support for why the SCT is inappropriate to use, nor why long-term benefits are "uncertain;" OHUG should logically provide near-perpetual resiliency benefits since the line will be permanently protected from trees and weather.

Q. What does Mr. Fitzhenry say about the Company's completed OHUG pilot?

A. On page 18 of his direct testimony, Mr. Fitzhenry states that the pilot "was not completed as planned" because some initial projects had to be replaced with others. He says that these issues indicate that the Company cannot scale its underground "from 8.8 miles completed

in the (p)ilot to 400 miles in this proceeding," and he states that substituting projects may lead to fewer benefits.

Q. How do you respond to these criticisms?

A. I disagree with Mr. Fitzhenry's contention that the pilot was not completed as planned. Any plan may require changes when it faces the reality of execution, but this does not mean the plan was unsuccessful. A hallmark of a successful organization is that it can make adjustments and adapt as challenges arise. In this case, the Company faced challenges with some initially proposed projects, but the Company was able to quickly find equivalent alternatives such that the same volume of work was still performed in the same timeframe. This agility indicates that the Company is capable of adapting to workplan challenges and continuing to get beneficial projects completed. It is also important to note that the Company is not proposing to immediately scale from 8.8 miles of OHUG work to 400 miles in this proceeding. The Company is only proposing to scale to 50 miles in this proceeding. The Company's long-term strategy is to scale to 400 miles, but not without first going through interim steps such as those proposed in the instant case.

Finally, because all undergrounding projects use the same selection criteria, each project should have generally similar benefits, even if a substitution is involved.

VIII. REBUTTAL OF ABATE WITNESS YORK

Q. How does Ms. York address the Company's distribution O&M?

A. On page 5 of her direct testimony, Ms. York notes the Company's recent distribution O&M has been between $640 million and $680 million per year, but in the instant case it proposes to increase it to $804 million. She opines that this is an excessive increase, and identifies several areas of proposed disallowances.

Q. Is there a common focus in how Ms. York proposes disallowances?

A. I note that several of her sub-program reviews focus on the "Other Adjustments" column in Exhibit A-128 (MPK-18), and multiple disallowances are based on the idea that these adjustments are not properly supported.

Q. Is there a problem with interpreting Exhibit A-128 (MPK-18) in this way?

A. Yes. Exhibit A-128 (MPK-18) should not be understood to suggest that the Company projected distribution O&M spending by starting with the most recent historical year, adding inflation, and then making adjustments from that level. In fact, the Company does not develop its projected distribution O&M spending in this manner; while each O&M sub-program is a little different, projected distribution O&M spending is usually based on a projected level of work, and the specific approach for each O&M sub-program is discussed throughout my direct testimony.

Please refer to page 124, line 5, through page 125, line 3, of my direct testimony for an explanation of how to properly understand Exhibit A-128 (MPK-18). The purpose of the exhibit is to illustrate what amount of the Company's projected O&M spending is tied to inflation, particularly so that interested intervenors can see the impact of different inflation rates. At no point is my direct testimony trying to specifically support the "Other Adjustments" column in and of itself; my testimony supports the total projected spending amount based on the total amount of work needed.

Q. What is Ms. York's recommendation regarding the Company's projections for the Non-Forestry Reliability O&M sub-programs?

A. On page 7 of her direct testimony, Ms. York states that the "Other Adjustments" for LVD Lines Reliability O&M, HVD Lines Reliability O&M, and LVD Substations Reliability

O&M are not supported. She goes on to state that the Company did not provide enough detail on how these sub-programs were projected. She recommends that the $10,003,000 in "Other Adjustments" for these sub-programs be disallowed.

Q. Do you agree with this recommendation?

A. No. First, as stated above, the Company supported the total sub-program expenditures, and not just the "Other Adjustments." Second, note that I have already discussed these sub-programs and the reasonableness of the Company's projections in my rebuttal to Ms. Durfee and Mr. Coppola. Finally, in discovery response 21870-AG-CE-0453, the Company provided detailed unitized information for these and other O&M sub-programs, illustrating the projected increasing workload that supports the projected increase in spending. I am providing this response as Exhibit A-222 (MPK-32).

Q. What is Ms. York's recommendation regarding sub-programs in the O&M and Metering without Service Restoration category?

A. On pages 10 through 12 of her direct testimony, Ms. York argues that the Company has not provided sufficient detail regarding how it projected its O&M costs for HVD Lines Demand O&M, LVD and HVD Substations Demand O&M, Staking, and Meter Services. She notes that my direct testimony did not provide detail about historical or projected work orders for some of these sub-programs. She recommends that the Commission disallow the $18,118,000 that are in "Other Adjustments" in Exhibit A-128 (MPK-18) for these sub-programs.

Q. Do you agree with this recommendation?

A. No. I will again note the issues with Ms. York's use of Exhibit A-128 (MPK-18), and I will also note that additional supporting work order details were provided in the discovery

response that is provided as Exhibit A-222 (MPK-32). Furthermore, I have supported the reasonableness of the Company's projections for HVD Lines Demand O&M and Staking O&M in my rebuttal to Ms. Durfee and Mr. Coppola, particularly the question about whether the Company's 7% growth rate for Staking O&M is appropriate.

Q. What is Ms. York's recommendation regarding the Training O&M sub-program?

A. On page 14 of her direct testimony, Ms. York states that, although Company witness Caitlin M. Tetrick has provided details about the Company's projected headcount that will drive increases in the Training O&M budget, the Company has not provided its assumptions related to the number of new employees who will require training during the test year. She also states that Company witnesses Sara E. Stewart and Richard T. Blumenstock have provided direct testimony related to challenges in obtaining necessary crews. As with the other O&M sub-programs, Ms. York recommends a disallowance based on the "Other Adjustments" amount in Exhibit A-128 (MPK-18).

Q. Do you agree with this recommendation?

A. No. For one thing, Company witness Stewart addresses forestry issues, and Company witness Blumenstock addresses generation. They are describing separate parts of the Company's workforce and/or contractors, so their testimony has no bearing on the distribution workforce that my direct testimony supports. Second, Ms. York is incorrect in focusing on the number of "new employees, apprentices, and external candidates that will actually require training during the projected test year." This implies that she believes that the Training O&M sub-program is only focused on on-boarding new employees. The Training O&M sub-program is actually used for training employees at various stages of employment. Page 167 of my direct testimony explains that the sub-program covers

expenses "whenever groups in the Electric Operations organization conduct official training courses." Page 168 states that the sub-program funds "union labor associated with additional hours of training, such as continuing education and required annual training courses." Company witness Tetrick has provided sufficient detail regarding the growth of the Company's Electric Operations workforce; since all employees require some amount of training, then the Training O&M sub-program budget will increase. Exhibit A-222 (MPK-32) shows that the number of total training hours is set to increase.

IX. REBUTTAL OF CEO WITNESS TAN

Q. What is Mr. Tan's assessment of the Company's regression analysis as presented in the instant case?

A. Mr. Tan has reviewed the regression analysis that the Company provided as Exhibit A-135 (MPK-25). On page 11 of his direct testimony, he concludes that the regression analysis as far as it regards reliability represents an "excellent job," and he finds value in it having been completed. I appreciate Mr. Tan's assessment in this area. Beginning on page 13 of his direct testimony, he discusses the part of the regression analysis that focused on customer disconnections and makes a number of recommendations in response to that, which will be addressed by Company witness Jessica R. Byrom.

Q. What recommendations does Mr. Tan make regarding future reliability regression analyses?

A. On pages 12 and 13 of his direct testimony, Mr. Tan recommends that the Company's next regression analysis (which will be required in its next rate case) should focus on a narrower set of reliability metrics using the same independent variables.

Q. Do you agree with this recommendation?

A. I do not have any concern with this recommendation. The Company hopes that future iterations of the reliability regression analysis will continue to focus on the most salient issues, and Mr. Tan's recommendation to narrow the focus will likely help with that.

X. REBUTTAL OF CEO WITNESS SHAVER

Q. What is Mr. Shaver's position on the Company's VCRP?

A. On page 4 of his direct testimony, Mr. Shaver states that he supports the VCRP, but that he recommends several "enhancements" to it. He goes into greater detail about this on pages 12 and 13 of his direct testimony, where he notes that the Company has presented the VCRP as a 10-year $600 million effort, yet has only proposed $30 million in investments in the test year in the instant case. He asks that the Company provide further detail about its total spending plan, as well as information regarding the six substations that are part of the VCRP that were already included in the Reliability Roadmap.

Q. How do you respond to this?

A. The Company is proposing to invest $30 million in the test year for two reasons. First, because it is a new initiative, the Company is seeking regulatory support from the Commission at an initial level before scaling up to a fuller annual spending level. Second, because the VCRP includes new types of work related to the development of high-reliability mainline three-phase circuits, the Company plans to do a smaller amount of work in the first year before scaling up, as opposed to trying to go "zero-to-60" in the first year. The Company's planned glidepath for the VCRP is based on investing $20 million in 2026, $40 million in 2027 (with the $30 million test year amount derived from the test year overlap between 2026 and 2027), and $67.5 million each year after that through 2035. Exact amounts may vary slightly from this based on specific projects selected in individual

future years; the Company has not yet identified specific projects beyond the test year in the instant case. It is not clear what information Mr. Shaver is seeking regarding the six new substations. He asks for details about "which substations these are," but these are new substations that will be built but which do not exist yet, so there is no current information about them. However, the $200 million dollars proposed for fractionalization in the VCRP does include those six new substations.

Q. What does Mr. Shaver say about the Company's reliability regression analysis?

A. On page 15 of his direct testimony, Mr. Shaver concludes, in conjunction with Mr. Tan, that the regression analysis has provided useful insight into reliability on the Company's system. Mr. Shaver also appears to agree that the regression analysis provides useful support for the VCRP. However, he also argues that the regression analysis should not be a stand-alone study, but that it should also "directly inform the Company's overall spending, including areas such as O&M and storm response." He recommends that the Company provide this kind of detail.

Q. How do you respond to this?

A. Mr. Shaver's recommendation here is unclear. The regression analysis supports the VCRP, which represents a significant investment in EJ communities. However, the regression analysis is not intended in the first place to serve as a comprehensive tool that governs all parts of the Company's electric operations or storm response. The reliability-related portions of the regression analysis were designed to[3]:

1. Quantify differences in the experiences of two groups of customers – those in EJ census tracts and those outside of them,

[3] Refer to Exhibit A-135 (MPK-25), pages 2 and 3 (the "Executive Summary" section).

2. Understand whether groups of customers may be disadvantaged or more exposed to disruptions in service than other customers, and

3. Assess how different characteristics of circuits relate to circuit reliability.

While the Company can always evaluate new ways to extract insights from this and future iterations of the regression analysis, it is not designed to provide direction on how the Company should allocate its O&M dollars in a comprehensive way.

Q. Does Mr. Shaver have any further recommendations?

A. On pages 17 and 18 of his direct testimony, Mr. Shaver recommends several ways in which the Company should track the impacts of the VCRP.

Q. Do you agree with this?

A. Mr. Shaver's recommendations for assessing the impacts of the VCRP seem generally reasonable. However, the first year of VCRP investments will not be complete until the spring of 2027, and there will likely be some lag after that time until the Company has sufficient "after" data to begin to draw conclusions, so little "before and after" analysis will be available in the immediate future.

XI. REBUTTAL OF CEO WITNESS KENWORTHY

Q. What is Mr. Kenworthy's position on virtual power plants ("VPPs")?

A. On page 3 of his direct testimony, Mr. Kenworthy recommends that the Commission move "from study to implementation [of VPPs] by requiring the Company to develop a near-term VPP program that delivers measurable value to customers and the grid." On subsequent pages, he provides details about what he believes this should entail; among the key points are that the Company should be able to create a full-fledged VPP program quickly, without needing a pilot (see page 5 of his direct testimony) and that it is possible to establish a

VPP within six months. Company witness Scott A. McPhail addresses the bulk of Mr. Kenworthy's recommendations on VPPs, but I also have concerns.

Q. What are your concerns?

A. I disagree with the suggestion that VPPs can be deployed in the Company's service territory starting immediately, reaching operational status within six months, without the need for any kind of pilot. Mr. Kenworthy suggests that VPPs are a mature concept that have been standardized in such a way that any utility can easily plug and play them onto its own system. Mr. Kenworthy's own evidence indicates that this is not the case. Page 13 of his direct testimony suggests that Exhibit CEO-4 provides evidence that VPPs reliably deliver benefits for the grid. But Exhibit CEO-4 seems to summarize a test event in California that just took place on July 29, 2025. This suggests the California parties involved have only just performed an initial demonstration of a new concept. This does not lead to a conclusion that VPPs are ready for deployment nationwide.

Each state has its own regulatory construct, and Michigan's is different from California's. There is no assurance that even a mature and well-established VPP in California could be transplanted wholesale to Michigan. Furthermore, the test event summarized in Exhibit CEO-4 was apparently coordinated with the California Independent System Operator ("CAISO"); there is no assurance that a VPP that works in CAISO could be transplanted wholesale to a utility operating in the Midcontinent Independent System Operator, Inc. region. Therefore, it is not correct to suggest that any conceptual VPP – especially one that appears to have just been tested two months ago – could be wholeheartedly adopted by the Company without first determining if it would work on the Company's system and in the Company's environment, which would necessitate some kind

of piloting by the Company. The workgroup described by Company witness McPhail could include discussion on the best approach to do this.

Q. What is Mr. Kenworthy's recommendation regarding non-wires solutions ("NWS")?

A. On page 20 of his direct testimony, Mr. Kenworthy recapitulates the Company's experiences with NWS since 2017 and his own arguments from Case No. U-21585 about how the Company could be deploying NWS now or in the immediate future rather than waiting for "off-the-shelf" solutions to be available. On page 21, he responds to the Company's intention to create a new NWS pilot by saying that "the time for pilots is over" and that the Company should now begin developing a formal program. On page 22, he seems to connect this argument to his argument about VPPs, saying that VPP program design should be informed by NWS analysis.

Q. How do you respond to this?

A. I continue to maintain that the Company must do another NWS pilot in order to demonstrate that an NWS will in fact deliver clear and consistent benefits for the Company's system, and that it can operate reliably on the Company's system. This is especially important since the Company's prior NWS pilots provided, at best, mixed results. Unless the Company is confident that a given NWS scheme will work, it would be irresponsible to begin implementing a program that may not be effective. This is particularly important as the Company would like to use a new pilot to explore using an NWS to provide reliability and resiliency benefits, whereas prior pilots have only looked at capacity deferral.

Q. How do you respond to Mr. Kenworthy's connection of VPPs to NWS?

A. In the Distributed Energy Resource Management System ("DERMS") workgroup discussed by Company witness McPhail, NWS could be an additional topic for discussion. Indeed, Mr. Kenworthy's discussion of the two topics in his testimony implies that there is overlap between the two concepts. But the synergy between VPPs and NWS also provides further evidence that neither concept is ready for immediate program-level deployment. Exhibit CEO-3 is the Department of Energy's "Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update" and is heavily cited by Mr. Kenworthy. Much of Mr. Kenworthy's discussion centers around "basic VPPs" – these are the schemes that can allegedly be deployed in six months. But the broader context of the report makes these basic VPPs sound closer to pilots in all but name. For example, Exhibit CEO-3, page 35, says that "many basic VPPs have been managed by customer programs teams with little to no impact to other functional groups within utilities; this limits the potential benefits of the VPP for the broader utility system. In contrast, leading utilities who operate more sophisticated VPPs have incorporated them into integrated planning processes and operations." In other words, delivering the grid-wide benefits contemplated by Mr. Kenworthy requires the development of sophisticated VPPs. The report indicates that such programs exist in places, but they are not easily or rapidly built. Notably, Exhibit CEO-3, page 28, states that sophisticated VPPs "may require the installation of additional hardware and software that provide (1) higher-resolution visibility into distribution grid conditions through sensors and improved data analytics and (2) more frequent and localized dispatch of DERs." In other words, the Company would not be in a position to deploy the kinds of VPPs or NWS that Mr. Kenworthy is seeking unless and until it has

made the appropriate foundational investments, particularly a DERMS. Since the Company does not have a DERMS, and the justification for one is an intended focus of the workgroup, it is not reasonable to suggest that the Company can immediately begin creating VPPs or NWS on its system.

XII. REBUTTAL OF CUB WITNESS BUNCH

Q. How does Mr. Bunch discuss the Company's reliability and its connection to planned investments?

A. On page 9 of his direct testimony, Mr. Bunch notes that in 2023 the "average Consumers customer went 913 minutes without power," an apparent reference to all-weather SAIDI, compared to a U.S. average of 342 minutes. He opines that this reliability performance should not be justified by an increase in rates (underpinned by increased investments in the system), suggesting that companies in competitive markets (presumably in other industries or perhaps in deregulated utility environments) would not be able to do this. Mr. Bunch concludes that the Company should be expected to deliver electricity to customers at rates similar to comparable utilities and with similar reliability, and that it would be unreasonable to grant rate increases to help the Company improve against reliability benchmarks.

Q. How do you respond to this argument?

A. I disagree with Mr. Bunch. For one thing, he has picked a single data point with which to assess the Company's reliability. All-weather SAIDI was considerably lower in 2022 and 2024, for example, and SAIDI excluding MEDs is also an industry-standard way of assessing reliability (indeed, the Company's Reliability Roadmap is based on improving SAIDI excluding MEDs – this is the reliability benchmark the Company is trying to improve against). Mr. Bunch's reference to hypothetical unnamed companies in other

industries is not relevant to this discussion because Consumers Energy does not exist in that environment; it provides electricity as a regulated utility under the regulatory construct established by Michigan law. Speculating about how the Company would fare in a competitive market, however Mr. Bunch would define that, is not relevant. Finally, it is unreasonable to argue that the Company has poor reliability while also contending that the Commission should not approve rate increases to fund reliability improvements.

Q. What is Mr. Bunch's position on which investments in distribution reliability should be approved?

A. On page 36 of his direct testimony, Mr. Bunch recommends that the Commission approve the Company's projected increases in line clearing and in LVD pole replacements. However, he classifies these increases as a "surge," and he and Douglas B. Jester (witness for NRDC, Sierra Club, and CUB) have developed a proposed deferral mechanism that classifies certain "surge" costs that would be kept out of rate base and only recovered later. Company witness Stewart addresses the Company's plans for line clearing, but I would note that it is not reasonable to remove the capital costs for pole replacements from rate base. Current customers do not cover the full capital investments in the first place, since the full revenue requirement is not recovered in a single year. See also the rebuttal testimony of Company witness Patrick D. Daly for additional discussion.

I am also concerned that, other than line clearing and LVD pole replacements, Mr. Bunch believes all other reliability investments should be held at "PAI-adjusted current levels," referring to a methodology that he has developed to index spending levels to inflation.

Q. Why are you concerned about this recommendation?

A. As I stated on page 41 of my direct testimony, it is important for the Company to have a diverse portfolio of investments to improve reliability, rather than going all-in on one or two types of activities; see also page 46, line 1, through page 47, line 2, of my direct testimony. Line clearing work is certainly an important part of the Company's reliability strategy, but pages 35 through 37 of my direct testimony have already provided a detailed explanation as to why it cannot be the only solution. LVD pole replacements are certainly an important part of the Company's plan as well, given their rate of deterioration, but as page 32, Figure 13 of my direct testimony illustrates, the Company's increased investment in LVD pole replacements will largely just allow the Company to hold the current line on SAIDI. As Figure 13 shows, multiple other investment categories in LVD and HVD play a role in the Company's holistic approach to improving reliability. Mr. Bunch's proposal would simply cause deterioration on the system to rapidly accelerate.

Mr. Bunch's recommendation is, in any case, vague. He recommends that the Commission "hold other reliability investments at PAI-adjusted current levels." It is not clear which investments he intends to include in this recommendation.

Finally, I disagree with Mr. Bunch's suggestion at page 36 of his direct testimony that the Company should invest in a very limited range of work in order to "make it easier to determine what additional reliability actions may be needed next, after the proverbial dust settles." I disagree with the implication that the Company cannot tell which reliability investments are beneficial. The Company has been documenting the specific reliability benefits of many types of investments over the years, particularly but not limited to Zonal

Health Improvements, and has provided evidence in this case (and in recent cases) about the percentage improvements that those projects make.

Q. What is Mr. Bunch's assessment of the Company's proposed OHUG plan?

A. On pages 48 and 49 of his direct testimony, Mr. Bunch states that the Company did not perform a benefit cost analysis ("BCA") for each proposed OHUG project. See my rebuttal to Mr. Coppola on this topic. Mr. Bunch also states that, based on his own analysis, half of the benefits of proposed OHUG work are attributable to a small minority of the work. He explains that he reviewed the customer-outage minutes avoided ("CMI") for the proposed projects in Exhibit A-167 (JMP-2), page 21, and calculated a present value of these CMI benefits for customers. In his Figure 3, he shows that half of the benefits are tied to just 11.3 of the Company's proposed 50 miles of projects. He recommends that the Company's OHUG work in the test year be limited to these 11.3 miles.

Q. Do you agree with this recommendation?

A. No. Mr. Bunch's model is incomplete because it is based solely upon the present value of avoided interruption costs to customers from an undergrounding project. This value is only one factor included within the SCT. In short, Mr. Bunch ignores many of the costs included in a BCA such as Return on Equity, interest, depreciation, taxes, O&M that customers will pay in return for the improved reliability benefits, and ignores the costs of alternatives to undergrounding the feeder like continued vegetation management. As a result, Mr. Bunch's alternative analysis is akin to a "do-nothing" scenario whereby the Company would not invest in the maintenance of equipment or vegetation on the feeder and would not invest in crew time or materials to restore customers when an outage occurs. Although Mr. Bunch leverages my own analysis to utilize the Interruption Cost Estimate ("ICE")

calculator in outlining the avoided interruption costs for customers, that analysis is misused. Because the ICE calculator has been limited to costs associated with outages that only last up to 24 hours, Mr. Bunch is likely understating the value of the project's impact on avoided interruption costs to customers given his analysis does not take into consideration the costs of alternatives.

XIII. REBUTTAL OF MNSC WITNESS PALMER

Q. What is Ms. Palmer's recommendation on the need to produce an AMI business case?

A. On page 9 of her direct testimony, Ms. Palmer recommends the Company continue to produce an AMI benefit analysis in subsequent rate cases.

Q. Do you agree with this recommendation?

A. No. In Case No. U-21389, the Commission has already clarified that the AMI business case was no longer needed because the value of the reporting was less about supporting a BCA for meters that had long been installed. The Company was directed to substitute the business case with AMI value-focused metrics that are discussed in my direct testimony. See my direct testimony, page 188 and Exhibit A-133 (MPK-23).

XIV. REBUTTAL OF GLREA WITNESS BOEHNKE

Q. What is Mr. Boehnke's thesis on VPPs?

A. On pages 7 and 8 of his direct testimony, Mr. Boehnke states that my direct testimony and discovery responses indicate that the Company does not believe that VPPs and other Distributed Energy Resource ("DER")-related applications can deliver reliability and resiliency benefits. Mr. Boehnke then extensively discusses the subject of VPPs, broadly agreeing with Mr. Kenworthy that VPPs are ready for immediate widespread deployment by the Company.

Q. Do you agree with his assessment?

A. No. For the reasons I discussed above in response to Mr. Kenworthy and discussed in the rebuttal testimony of Company witness McPhail.

XV. REBUTTAL OF UCC WITNESS CIRA-REYES

Q. What does Mr. Cira-Reyes say about the Company's reliability?

A. Beginning on page 47 of his direct testimony, Mr. Cira-Reyes expresses concern with the Company's reliability, and he makes the connection to the particular detrimental impacts that this has on disadvantaged communities. On pages 48 and 49, he reviews the actions that the Company has taken in recent years to review and address reliability issues in such communities (*i.e.,* in EJ communities), and he seems to acknowledge that progress has been made but ultimately concludes that the Company must act "more expeditiously" to address this issue. Specifically, he believes that the Company must do more to meet the investment targets for the VCRP, and that the Company must take more action to address inequities revealed in the regression analysis.

Q. How do you respond to these two recommendations?

A. As outlined on page 51 of his direct testimony, Mr. Cira-Reyes' concerns about whether the Company will meet its investment targets for the VCRP largely mirror the concerns that Mr. Shaver also expressed. Please refer to my rebuttal of Mr. Shaver for discussion on this.

On pages 52 and 53 of his direct testimony, Mr. Cira-Reyes states that the regression analysis in Exhibit A-135 (MPK-25) confirms that the distribution system has inequities based on race and socioeconomic status, and he believes the Company is not making a priority to address these inequities. Specifically, he takes issue with my statement in my direct testimony that the analysis concludes that, on average, EJ, urban, low-income,

and higher-percent-minority census tracts have better reliability. Similar to arguments made in Case Nos. U-21389 and U-21585, Mr. Cira-Reyes argues that average comparisons likely conceal inequities. I believe the full regression analysis has addressed this concern. Exhibit A-135 (MPK-25), pages 24 through 26,[4] lists several types of analyses that were used in the overall regression analysis project. One type, the binary difference-in-means t-test, was used to make binary overall comparisons between different sets of census tracts. This was an early phase of the project and was intended to (a) validate the comparisons made in Case Nos. U-21389 and U-21585 on a more formal statistical basis and to (b) conduct an initial first-pass analysis upon which later more detailed and nuanced analyses could be based. The detailed results on this binary difference-in-means t-test are shown on pages 28 through 40 of Exhibit A-135 (MPK-25), with the results discussed on pages 40 and 41. Those results reached the conclusion that, on average, EJ, urban, low-income, and higher-percent-minority census tracts have better reliability on average. Page 76, line 18, through page 77, line 2 of my direct testimony report this conclusion and notes that the analyses provide statistical validation for the Company's conclusions in Case Nos. U-21389 and U-21585.

My statement on page 78 of my direct testimony, with which Mr. Cira-Reyes takes issue, that "[t]here is nothing apparently systemic or unique about EJ census tracts (or other potential groupings of disadvantaged census tracts) as a whole that give them worse reliability, since they have better than average reliability than other census tracts," is tied to this conclusion from the binary difference-in-means t-test. When I say that there is nothing systemic or unique about EJ census tracts in this context, I mean that there is no

[4] My references to this exhibit cite the page numbers out of 143 at the top right of each page, not the original document page numbers at the bottom center.

across-the-system evidence that they experience worse reliability. If there were systemic issues, we would expect to see EJ census tracts facing worse reliability outright, but that is not the case.

Still, my direct testimony immediately goes on to acknowledge that the later more nuanced components of the regression analysis do indicate that there are some areas in which some EJ census tracts or circuits have worse reliability outcomes. The Company agrees with Mr. Cira-Reyes' concern that members of EJ communities are particularly vulnerable to power interruptions, which is why the Company has developed the VCRP. But this is not in response to a systemic issue, since there is no evidence of one; it is in response to the relatively isolated local issues that the regression analysis has helped the Company identify. The issues identified in the regression analysis warrant further study, as I said in my direct testimony, because further study can help the Company better understand those isolated issues and be better able to address them.

Q. What recommendations does Mr. Cira-Reyes have regarding the IRM?

A. On pages 56 and 57 of his direct testimony, Mr. Cira-Reyes notes that in Year 1 of the IRM authorized in Case No. U-21389, the Company overspent the authorized amount in some areas and underspent in others. He states that the Company should elaborate on these inaccuracies, and states that the Company must show through its reconciliation of Year 2 that it can do better.

Q. How do you respond to this?

A. The Company's reconciliation of Year 1 of the IRM is ongoing in a separate contested proceeding in Case No. U-21918. The Company provided details in that case on its Year 1 spending, and that case is a more appropriate venue to seek further details on Year 1

spending. Year 2 is currently in progress and will be reconciled as required in a separate contested proceeding beginning in 2026.

Q. What is Mr. Cira-Reyes' recommendation regarding equity in the IRM?

A. On pages 57 and 58 of his direct testimony, Mr. Cira-Reyes states that the Company's equity analysis should have been more thorough. He acknowledges the Company's evidence in Case No. U-21918 that it made a disproportionately high amount of Year 1 IRM investment in EJ communities, but he supposes that it is possible that EJ communities may have had even greater needs than that and the Company should have analyzed whether that is the case or not.

Q. Do you agree?

A. Again, the ongoing Case No. U-21918 is a better venue than the instant case to seek more detailed information about Year 1 IRM investment. That said, given the results of the regression analysis discussed above – that there are some nuanced reliability issues in some EJ communities, but that EJ communities do not have systemically poor reliability – I do not believe there is evidence that EJ communities should have had an even more disproportionately large share of Year 1 IRM investment. Ultimately, though, the Company is seeking to include the VCRP in its IRM proposal in the instant case precisely to ensure that the IRM has a positive impact on equity.

Q. What is Mr. Cira-Reyes' recommendation regarding the Company's public-facing GIS map regarding EJ reliability data?

A. On page 65 of his direct testimony, Mr. Cira-Reyes acknowledges the Company's map and expresses appreciation, but also lists ways that he believes it could be made more user-friendly.

Q. Do you agree with this recommendation?

A. The Company can certainly look for ways to make continuous improvements to this public-facing tool. However, saying that the map must be easily used by any member of the general public creates a very broad and vague target condition. The existing map was ultimately a creation of the proceedings of Case No. U-21389. In that case, the Company fielded numerous discovery requests from Staff seeking extensive amounts of GIS data, as Staff was conducting its own EJ analysis in that case. Those discovery requests were time-consuming and in some cases could not be completed in a timely fashion. In that case, Staff proposed that the Company create a public-accessible map with downloadable data on demand to reduce such a bottleneck in the future. As such, the current map was largely developed based on Staff feedback, particularly as Company representatives met with Staff on multiple occasions between the Order in Case No. U-21389 and the publication of the map.

Q. What is Mr. Cira-Reyes' recommendation regarding DERs and hosting capacity analysis ("HCA") in EJ communities?

A. On pages 66 and 67 of his direct testimony, Mr. Cira-Reyes indicates that EJ communities stand to benefit from DER adoption, but expresses concern that EJ communities may have low hosting capacity to accommodate them. If EJ communities do have low hosting capacity, then he states that the Company should upgrade them.

Q. How do you respond to this?

A. The Company published its more detailed Phase II HCA map on September 30, 2025, shortly after Mr. Cira-Reyes' testimony was filed. This provides considerably more detail, available to any member of the public, on how much hosting capacity is in each location,

and would enable any party to determine how much hosting capacity is in an EJ community (or any other community covered by the analysis). The map is published at: https://cms.maps.arcgis.com/apps/instant/lookup/index.html?appid=b90ff63b338043b7bcae43dd685a419d.

In addition to this publicly available information, the Company has done further analysis on its hosting capacity, and the average circuit-level hosting capacity on an EJ circuit is 8.9 MW, compared to the Company's systemwide average of 6.4 MW. This would suggest that EJ circuits are usually not hosting capacity-constrained. However, we have already discussed how systemwide averages can mask local peculiarities. To the extent that individual EJ circuits are found to be constrained, the Company would consider making capacity investments in those circuits.

XVI. REBUTTAL OF METC WITNESS FLECK

Q. What is Mr. Fleck's recommendation regarding coordination and alignment between the Company and METC on transmission and distribution planning?

A. Mr. Fleck's testimony generally indicates support for Company's distribution plan as defined in the Reliability Roadmap, and extols the benefits of coordination between METC and the Company. On page 11 of his direct testimony, he proposes the establishment of a stakeholder working group to align transmission and distribution planning with state electrification goals, which would represent formal coordination between the Company and METC.

Q. Do you agree with this recommendation?

A. Similar to the Company's position in recent rate cases, Consumers Energy is happy to have any discussions sought by METC at their request, and the Company will engage in informal

coordination (and indeed already does so in various ways). However, the Company does not believe that the Commission needs to order a formal coordination process.

XVII. REBUTTAL OF MEIU WITNESS ALBERS

Q. What is Mr. Albers' recommendation regarding the Company's inventory of equipment with long acquisition lead times?

A. In Case No. U-21585, Mr. Albers recommended that, in the instant case, the Company "identify hardware commonly associated with interconnecting advanced energy technologies, like DERs and EV charging facilities, that has long acquisition lead times." The Commission ordered this, and I provided an analysis in my direct testimony, which was supplemented during this case by discovery provided to MEIU (provided by Mr. Albers as Exhibit MEIU-3.2). Mr. Albers' testimony in the instant case is largely concerned with assessing this. On page 9, he concludes that the Company likely has sufficient inventory. However, he recommends that in order to "ensure greater certainty for developers," the Company should "make its inventory of equipment with long acquisition lead times available to DER and EV projects initiated by third parties on the same basis that such equipment is available to projects that it initiates."

Q. How do you respond to this?

A. Based on my understanding of Mr. Albers' request, the Company already does this. When it comes to projects that require long lead time equipment, the Company treats projects on a first-come, first-served basis in which inventory is made available for projects in order of project approval, without preferential treatment for internal projects. Regarding interconnection projects specifically, the Company creates and schedules work orders in the order that the interconnection approval process is completed. It is important to clarify that the Company does not sell inventory to third-party customers who would own and

maintain their own equipment. The Company is interpreting Mr. Albers' proposal to mean only projects initiated by third parties, not projects conducted by third parties.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Next is company witness, Jon J Koetje. Mr. Koetje had direct testimony consisting of a cover page and 24 pages of questions and answers, and he also sponsored Exhibits A-139, A-140, and A-141.

THE COURT: Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct testimony of Jon Koetje is bound in the record and Exhibits A-139 through A-141 are admitted.

(At 2:59 p.m., Exhibits A-139 through A-141 admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-21870

DIRECT TESTIMONY

OF

JON J. KOETJE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Jon J. Koetje. My business address is 700 East Sternberg Road, Norton Shores, Michigan 49441.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") where I am the Director of Engineering, Procurement, and Construction ("EPC") Project Management for Fossil Generation.

Q. Please describe your educational background and work experience.

A. I have a Bachelor of Science in Chemical Engineering from Michigan Technological University. I earned a Master Certification in Project Management from George Washington University. I am a certified Project Management Professional® and a licensed Professional Engineer in the state of Michigan.

In 1983, I began employment at Sun Chemical Corporation in Muskegon, Michigan as a Process Engineer eventually working my way up to Manager of Maintenance, Engineering, and Reliability. My responsibilities included overseeing the maintenance, engineering, and reliability departments for an organic pigments production facility. My duties included management of general maintenance activities, outage planning and execution, implementation of capital projects from inception through execution, start-up testing and commissioning, and management of reliability that included non-destructive testing and vibration analysis.

In 2005, I joined Consumers Energy in the Equipment Services organization, as a Sr. Engineer II, where I managed the implementation of capital projects at the D.E. Karn ("Karn") and J.H. Campbell ("Campbell") plants.

In 2008, I progressed to the position of EPC Project Manager II. My responsibilities in that position continued the management of capital projects at the Karn and Campbell plants.

Between 2013 and 2020, I progressed through the project management job family to the position of EPC Sr. Project Manager I, where I managed increasingly complex projects and eventually a group of project managers that managed a portfolio of projects at the Jackson Generation Station, Zeeland Generation Station, and Karn and Campbell plants. In 2020, Consumers Energy promoted me to my current role as Director of EPC Project Management – Fossil Generation where my duties include the management of capital projects for the fossil portfolio.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony concerning decommissioning, and ash disposal in the Company's 2024 Electric Rate Case, Case No. U-21585.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to present the actual 2024 expenses for the Karn Units 1 and 2 and Campbell Units 1, 2, and 3 decommissioning as well as to present the actual 2024 coal ash disposal costs for Karn Units 1 and 2, Campbell Units 1, 2, and 3, and the Classic 7. In addition, my testimony presents updated projected decommissioning expenses for Campbell Units 1, 2, and 3 consistent with the projection presented in Case No. U-21585 as well as updated projected decommissioning expenses for Karn Units 1 and 2 between 2025 and 2026.

Q. Please describe the generating units for which the decommissioning and coal ash disposal costs are being incurred.

A. Five coal-fired units have now been approved for retirement. Karn Units 1 and 2 are two plants approved for retirement, as detailed in the Company's Commission-approved 2018 Integrated Resource Plan ("IRP") in Case No. U-20165. Campbell Units 1, 2, and 3 have also been approved for retirement, as detailed in the Company's Commission-approved 2021 IRP in Case No. U-21090.

Classic 7 includes three units at the J.R. Whiting ("Whiting") Generating Complex near Luna Pier; two units at the B.C. Cobb ("Cobb") Generating Plant in Muskegon; and two units at the Karn/J.C. Weadock ("Weadock") Generating Complex near Bay City. While all the Classic 7 units have been decommissioned, and the Cobb and Whiting sites have since been divested, the Company still has ongoing responsibility for coal ash disposal costs, including ground water monitoring.

Q. Please detail how your direct testimony is related to the direct testimony of other Company witnesses.

A. The projected spending associated with the Karn Units 1 and 2 Decommissioning, Campbell Units 1, 2, and 3 Decommissioning, and coal ash disposal sponsored in my testimony are part of the overall generation asset strategy explained and sponsored by Company witness Richard T. Blumenstock. In addition, Company witness Patrick D. Daly will discuss the regulatory asset treatment of the actual 2024 expenses for Karn Units 1 and 2 decommissioning, Campbell Units 1, 2, and 3 decommissioning, as well as coal ash disposal costs for Karn Units 1 and 2, Campbell Units 1, 2, and 3, and the Classic 7.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following Exhibits:

Exhibit A-139 (JJK-1)	Karn Units 1&2 Decommissioning Plan Expenditures;
Exhibit A-140 (JJK-2)	Actual Coal Ash Disposal Plan Expenditures; and
Exhibit A-141 (JJK-3)	JHC Decommissioning Plan Expenditures.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into three sections.

Section I will support the reasonableness and prudence of the actual 2024 decommissioning expenditures associated with Karn Units 1 and 2 as well as the updated actual and projected Karn Units 1 and 2 Decommissioning Plan Expenditures between 2024 and 2026.

Section II will support the reasonableness and prudence of the actual Coal Ash Disposals expenditures at all Company coal generation sites for 2024.

Section III will support the reasonableness and prudence of the actual 2024 decommissioning expenditures associated with Campbell Units 1, 2, and 3 as well as the updated actual and projected Campbell Units 1, 2, and 3 Decommissioning Plan Expenditures between 2024 and 2030.

OVERVIEW

Q. Please explain why the Company is presenting its actual 2024 Karn Units 1 and 2 decommissioning and coal ash disposal expenses in this proceeding.

A. The Commission issued an Order approving a settlement agreement in the Company's General Electric Depreciation Case No. U-20849 ("U-20849 Settlement"). Paragraph 3(a) of the U-20849 Settlement provides for the recording of the Karn Units 1 and 2 decommissioning costs and the ash disposal costs for the Classic 7 and Karn Units 1 and 2 as spent, to a regulatory asset. Paragraph 3(a) further states that these costs may be requested for recovery in future base rate proceedings. Specifically, Paragraph 3(a) states:

> The decommissioning costs, less salvage value, related to D.E. Karn Units 1 and 2 and the ash disposal costs related to D.E. Karn Units 1 and 2 and the Classic 7 sites (i.e. the three units at the J. R. Whiting Generating Complex near Luna Pier, two units at the B.C. Cobb Generating Plant in Muskegon, and two units at the Karn/Weadock Generating Complex near Bay City) will be recorded, as spent, to a regulatory asset. The Company may request recovery in future base rate proceedings, and upon Commission determination that those costs are reasonable and prudent, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

Q. Has the Company previously presented its plans for the decommissioning and coal ash disposal costs for Karn Units 1 and 2 and its coal ash disposal cost for the Classic 7?

A. Yes. The Company originally presented its plans for the decommissioning and coal ash disposal costs for Karn Units 1 and 2 and its coal ash disposal cost for the Classic 7 in Case No. U-21224. The Commission-approved settlement agreement in that proceeding ("U-21224 Settlement") approved the Company's plans for decommissioning costs for

Karn Units 1 and 2 and coal ash disposal costs for Karn Units 1 and 2 and the Classic 7. Specifically, Paragraph 16 of the U-21224 Settlement stated:

> The Commission should approve the Company's proposed D.E. Karn Units 1 and 2 decommissioning plan and the amortization of the regulatory asset associated with the Karn Units 1 and 2 decommissioning costs and the Karn Units 1 and 2 and the Classic 7 ash disposal costs. The costs associated with Karn Units 1 and 2 decommissioning will be amortized through 2031 beginning in 2024 and the Karn Units 1 and 2 and Classic 7 ash disposal costs will be amortized over 10 years beginning in 2024.

Company witness Daly discusses the establishment of the regulatory asset for these costs and the proposed amortization in his testimony. The Company most recently updated its plans for the decommissioning and coal ash disposal costs for Karn Units 1 and 2 and its coal ash disposal cost for the Classic 7 in Case No. U-21585.

SECTION I

Karn Units 1 and 2 Decommissioning Plan

Q. Why is the Company decommissioning Karn Units 1 and 2?

A. The settlement agreement approved by the MPSC in its June 7, 2019 Order in the Company's IRP, Case No. U-20165, approved the retirement of Karn Units 1 and 2 in 2023. This retirement aligns with the Company's goal (as approved in its 2021 IRP, Case No. U-21090) to end coal use to generate electricity by 2025, meet Michigan's energy needs while continuing the transition to net zero carbon emissions by 2040, and meet customer needs with 60% renewable energy 20% clean energy sources by 2035 with an increase to 40% clean by 2040.[1]

[1] PA 235 of 2023 requires 80% of the Company's generation portfolio in 2035 to consist of clean energy resources. By 2040, PA 235 requires all of the Company's generation resources to consist of clean energy resources.

Q. Please discuss the Company's Karn Units 1 and 2 decommissioning plan expenses.

A. The Company's decommissioning plan for Karn Units 1 and 2 originally presented in Case No. U-21224 and most recently updated in Case No. U-21585 was based on an evaluation of eight separate factors, including: (1) capacity replacement costs; (2) impact of recovery of undepreciated book value; (3) customer rate impact analysis; (4) non-economic variables such as portfolio balance, employment, and community impact; (5) effect on contractual fuel obligations; (6) near-term revenue requirements; (7) conditions of existing equipment; and (8) execution risk.

The Karn Units 1 and 2 Decommissioning Plan consists of multiple activities beginning with the development of a strategic plan focusing on: stakeholder engagement, workforce and community transitions, future use analysis, divestiture analysis, physical transition of systems to a de-energized state, remediation of regulated materials, physical demolition of the plant assets, salvage of scrap metals, remediation of all impacted areas, backfill of soils to acceptable engineered specifications, restoration focused on maximizing redevelopment opportunities, and completion of project closure to a brownfield standard.

Q. What was the retirement date for Karn Units 1 and 2?

A. Consistent with the settlement agreement approved in Case No. U-20165, the retirement date was May 31, 2023. This date corresponded with the end of the Midcontinent Independent System Operator, Inc. ("MISO") 2022/2023 Planning Year.

Q. How were the cost projections in the Karn Units 1 and 2 Decommissioning Plan developed?

A. The projected costs consist of anticipated third-party costs as well as internal project administration costs. The projected costs were presented on Exhibit A-27 (JEB-1) in Case

No. U-21224, the Company's 2022 Electric Rate Case filing, and have been updated in each of the Company's subsequent electric rate case filings (i.e. Case Nos. U-21389 and U-21585). The most recent update was presented on Exhibit A-120 (JJK-1) in Case No. U-21585.

Q. What are the 11 major cost categories as outlined in the Company's Karn Units 1 and 2 Decommissioning Plan?

A. Exhibit A-139 (JJK-1), lines 1 through 11, column (a), identifies the 11 major cost categories associated with the Karn Units 1 and 2 Decommissioning Plan: 1) Utility Separation; 2) Decommissioning; 3) Abatement; 4) Demolition; 5) Asset Recovery; 6) Environmental; 7) Restoration; 8) Inventory Write Off; 9) Contingency; 10) Project Indirects; and 11) Interim Cost of Removal ("COR").

Q. What are the actual and projected costs as proposed in the Karn Units 1 and 2 Decommissioning Plan?

A. Table 1 below illustrates the total annual projected costs for the Karn Units 1 and 2 Decommissioning Plan based on the project schedule.

Table 1. Karn Units 1 and 2 Actual and Projected Decommissioning Costs ($000s)

Pre – 2022 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast	2026 Forecast	Total Actual and Forecast
$6,970	$7,557	$25,694	$21,294	$11,810	$3,994	$77,319

Q. What were the actual 2024 costs for Karn Units 1 and 2 decommissioning?

A. Table 2 below illustrates the actual 2024 expenditures for the Karn Units 1 and 2 decommissioning.

Table 2. Karn Units 1 and 2 2024 Actual Decommissioning Costs ($000s)

Activity	Projected	Actual	Variance
Utility Separation	**-**	**247,791**	**(247,791)**
Decommissioning	**-**	**256,344**	**(256,344)**
Abatement	**14,750,163**	**5,749,772**	**9,000,391**
Demolition	**11,447,658**	**9,667,091**	**1,780,567**
Asset Recovery	**(7,200,000)**	**(3,977,582)**	**(3,222,418)**
Environmental	**7,119,982**	**5,157,214**	**1,962,768**
Restoration	**-**	**4,485,202**	**(4,485,202)**
Inventory Write Off	**-**	**228,443**	**(228,443)**
Contingency	**10,000,000**	**-**	**10,000,000**
Project Indirects	**9,429,527**	**4,996,328**	**4,433,199**
Interim COR	**-**	**(5,516,418)**	**5,516,418**
Total	**45,547,330**	**21,294,185**	**24,253,145**

Exhibit A-139 (JJK-1), line (11), columns (d) and (e), further reflects these decommissioning expenses incurred in 2024 and a comparison to the projected expenditures presented in Case No. U-21224.

Q. How does the Company's decommissioning cost projection in this proceeding compare to the plan filed in Case No. U-21585?

A. The Company's decommissioning total project cost reflects a cost decrease of $13,208,533 below the updated amount presented in Case No. U-21585 of $90,527,610. The updated decommissioning costs are presented on Exhibit A-139 (JJK-1), lines 1 through 11 in columns (b) and (c). The actual and projected costs have been updated to reflect field conditions encountered and mitigation of risk as the project progresses as well as Utility Separation costs that were capitalized and are included in the testimony of Company

witness Blumenstock. I will describe each of the individual cost components and the basis for the actual costs and updated cost projections separately.

Q. Please discuss the basis for the change in the decommissioning plan for Karn Units 1 and 2.

A. Two main developments contributed to the projected cost of the decommissioning plan for Karn Units 1 and 2. The first of these is the field conditions encountered as the work progressed, particularly around the abatement and coal removal activities. The second is the mitigation of risk as the project has progressed.

Q. Please describe the costs which are included in Exhibit A-139 (JJK-1), line 1, column (a): Utility Separation.

A. Utility Separation represents the construction and equipment costs that were projected to be incurred to separate the equipment and utilities that are common to Karn Units 1 and 2 and Karn Units 3 and 4. Performance of this work allows Karn Units 3 and 4 to operate independently after Karn Units 1 and 2 were retired on May 31, 2023.

Q. What were the actual 2024 Utility Separation expenses?

A. The Company's actual Utility Separation expenses for 2024 were $247,791. This represents the portion of the Utility Separation costs that were not capitalized and are considered COR. Costs that were capitalized are included in the testimony of Company witness Blumenstock.

Q. How does the Company's actual 2024 cost of $247,791 for Utility Separation compare to the projected 2024 expenses presented in Case No. U-21585?

A. The Company's cost projection for Utility Separation was $247,791 higher than projected as some work that was planned for 2024 was delayed due to equipment long lead times experienced to complete Utility Separation projects.

Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 2, column (a): Decommissioning.

A. Decommissioning represents the costs of both plant personnel and construction to drain equipment, clean equipment, and de-energize the plant in preparation for transition to Abatement, Dismantling, and Demolition ("AD&D"). This includes site separation costs to isolate the plant from energized sources as well as costs to provide temporary power for use during AD&D.

Q. What were the actual 2024 Decommissioning expenses?

A. The Company's actual Decommissioning expenses for 2024 were $256,344.

Q. How does the Company's 2024 actual cost of $256,344 for Decommissioning compare to the projected 2024 expenses presented in Case No. U-21585?

A. The cost for decommissioning was $256,344 higher than projected, as some work that was planned for 2023 was delayed into early 2024 due to extension of the "Cold and Dark" outage.

Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 3, column (a): Abatement.

A. Abatement costs represent construction costs to complete asbestos abatement and removal of other regulated materials from the plant. This includes transportation and disposal of asbestos and other regulated materials.

Q. What were the actual 2024 Abatement expenses?

A. The Company's actual Abatement expenses for 2024 were $5,749,772.

Q. How does the Company's 2024 actual cost of $5,749,772 for Abatement compare to the 2024 projected expenses presented in Case No. U-21585?

A. The actual cost in 2024 for abatement was $9,000,391 lower than projected due to material re-characterization. Multiple materials that were inaccessible while the Karn Units 1 and 2 were operating were presumed to be asbestos for the purposes of bidding the Abatement work. Many of these materials, when tested, were found to be non-asbestos.

Q. Please describe the costs which are included in Exhibit A-139 (JJK-1), line 4, column (a): Demolition.

A. Demolition costs reflect the construction costs to completely dismantle and demolish the plant. This includes removal and recycling or disposal of non-metallic demolition debris.

Q. What were the actual 2024 Demolition expenses?

A. The Company's actual Demolition expenses for 2024 were $9,667,091.

Q. How does the Company's 2024 actual cost of $9,667,091 for Demolition compare to the projected 2024 expenses presented in Case No. U-21585?

A. Demolition expenses were $1,780,567 lower than projected in 2024 due to adjustments in schedule prioritizing Environmental and Restoration work in 2023.

Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 5, column (a): Asset Recovery.

A. Asset Recovery reflects the sale and scrap of surplus inventory.

Q. What were the actual 2024 Asset Recovery credits?

A. The Company's actual Asset Recovery credits for 2024 were ($3,977,582).

Q. How does the Company's 2024 actual credit of ($3,977,582) for Asset Recovery compare to the 2024 projected expenses presented in Case No. U-21585?

A. There was a change of ($3,222,418) reflecting adjustments in schedule prioritizing Environmental and Restoration work in 2023.

Q. Please describe the costs which are included in Exhibit A-139 (JJK-1), line 6, column (a): Environmental.

A. Environmental costs reflect the costs to remove and dispose of excess coal and impacted soil, close the bottom ash impoundment associated with Karn Units 1 and 2, and treat water removed for dewatering during Demolition activities.

Q. What were the actual 2024 Environmental expenses?

A. The Company's actual Environmental expenses for 2024 were $5,157,214.

Q. How does the Company's actual 2024 cost of $5,157,214 for Environmental compare to the projected expenses presented in Case No. U-21585?

A. The actual 2024 expense reflects a decrease of $1,962,768 due to actual bids for the bottom ash impoundment closure being less than anticipated and transfer of excess coal for reuse instead of landfilling.

Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 7, column (a): Restoration.

A. Restoration costs reflect the engineering costs to restore the property to final grade with controlled storm water management and establish vegetation.

Q. What were the actual 2024 Restoration expenses?

A. The Company's actual Restoration expenses for 2024 were $4,485,202.

Q. How does the Company's actual 2024 cost of $4,485,202 for Restoration compare to the projected expenses presented in Case No. U-21585?

A. The Restoration cost for 2024 were $4,485,202 higher than projected due to pulling Restoration work for the coal yard ahead in the schedule. In addition, more restoration expense is expected to be incurred due to discovery of more residual coal than expected in the coal yard.

Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 8, column (a): Inventory Write Off.

A. Inventory Write Off reflects the book value of the remaining plant inventory assets that cannot be sold or redeployed.

Q. What were the actual 2024 Inventory Write Off expenses?

A. The Company's actual Inventory Write Off expenses for 2024 were $228,443.

Q. How does the Company's 2024 actual cost of $228,443 for Inventory Write Off compare to the 2024 projected expenses presented in Case No. U-21585?

A. The 2024 actual expense reflects an increase in expense of $228,443 since less inventory was written of in 2023 than anticipated due to limited resources to complete the inventory write-off in 2023. Inventory write off was completed in early 2024.

Q. How does the Company's actual 2024 cost of $0 for Contingency compare to the 2024 projected expenses presented in Case No. U-21585?

A. There is a $10,000,000 decrease from the projection. Contingency funds were reduced due to the mitigation of risk or moved into other cost categories to cover realized risk.

Q. Will amounts labeled as contingency be recorded in the decommissioning regulatory asset?

A. No. Only amounts actually spent will be recorded to the regulatory asset. To the extent these contingency dollars are not spent, they would not be recorded to the regulatory asset and would not be requested for recovery.

Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 10, column (a): Project Indirects.

A. Project Indirects include Engineering & Supervision, Other Post-Employment Benefits, Pension, and Administrative & General costs.

Q. What were the actual 2024 Project Indirect expenses?

A. The Company's actual Project Indirect expenses for 2024 were $4,996,328.

Q. How does the Company's actual 2024 cost of $4,996,328 for Project Indirects compare to the projected expenses presented in Case No. U-21585?

A. The actual 2024 expense was $4,433,199 lower than the projection due to decreases in Engineering & Supervision, Other Post-Employment Benefits, Pension, and Administrative & General costs.

Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 11, column (a): Interim COR.

A. Interim COR includes the COR portion of projects that were previously implemented but have not been recovered in the depreciation rate case.

Q. What were the actual 2024 Project Interim COR?

A. The Company's actual Interim COR expenses for 2024 were ($5,516,418).

Q. How does the Company's actual 2024 cost of ($5,516,418) for Interim COR compare to the projected expenses presented in Case No. U-21585?

A. There was a change of ($5,516,418) reflecting Utility Separation costs that were capitalized and are included in the testimony of Company witness Blumenstock.

SECTION II

Karn Units 1 and 2 and Classic 7 Coal Ash Disposal Plan

Q. Please provide an overview of the Company's Karn Units 1 and 2 and Classic 7 Coal Ash Disposal Plan.

A. The United States Environmental Protection Agency ("EPA") promulgated new national criteria in 2015 to ensure coal ash facilities and management practices do not pose adverse effects on health and the environment. In response, the Company developed plans to protect against the risk of adverse impacts to health and the environment and to comply with the new rules. Specifically, the plans included closure activities for all unlined impoundments, accelerated landfill closures, and enhanced groundwater monitoring. Execution of these plans demonstrate the Company's continued dedication to protecting the state's natural resources and the health of surrounding communities. Since 2015, Consumers Energy has completed closure of many coal ash management units including all nine of its unlined impoundments. The Michigan Department of Environment, Great Lakes, and Energy ("EGLE") has agreed with the completion of closure activities for the nine units. Consumers Energy completed closure of its 125-acre Karn Landfill, which was

certified by EGLE, and has completed the first year (2023) of closure cap construction on the 272-acre Weadock Landfill.

Q. Has the EPA updated the closure criteria for coal ash sites?

A. Yes. In 2024 the EPA promulgated updated criteria for coal ash sites. In response, the Company continued closure activities at the Weadock landfill consisting of importing clay fill material, as well as raising ITC's and the Company's transmission towers. Installation of liner material was delayed for up to three years while the Company determines the impact of the new rules on the Karn Weadock site, and the Weadock landfill. The Company has started to investigate the overall impact of the new rules on the Karn site, as well as the Classic 7 sites. Facility evaluation reports are due in early 2026 which will help define future projects required at the sites.

Q. What were the Company's 2024 actual coal ash disposal costs?

A. Table 3 below illustrates the total actual 2024 expenditures for the Company's coal ash disposal plan.

Table 3. 2024 Actual Coal Ash Disposal Costs ($000s)

Site	Actuals 2024
DE Karn	**$ 1,448,223**
JC Weadock	**$ 19,796,598**
BC Cobb	**$ 86,264**
JR Whiting	**$ 85,824**
JH Campbell	**$ 30,729,853**
Total	**$ 52,146,763**

Q. Have the projected coal ash disposal costs changed from the previous filing?

A. No.

Q. How were the Coal Ash Disposal Plan costs developed?

A. Remaining coal ash disposal costs consist of long-term groundwater monitoring at Karn, Weadock, Cobb, and Whiting as well as closure construction activities consisting of construction of a remedial response for the Karn Landfill, design and construction of a remedial response for the Karn closed Bottom Ash Pond, continued installation of a final cover system to close the Weadock Landfill, addressing remedial action plan ("RAP") requirements at Campbell B-K which consists of constructing treatment wetlands and beneficiating the ash in B-K, and closure certification of the Cobb Ash Ponds 0-8 and Bottom Ash Pond. Groundwater monitoring activities are required by state and federal regulations and are performed in accordance with hydrogeological monitoring plans developed for each site in accordance with those regulations. The remedial response proposed for Karn Landfill is included in a RAP that has been approved and is currently being reviewed by EGLE. The Weadock Landfill has a Closure Plan that was approved by EGLE facilitating the accelerated closure of the landfill at a lower elevation. The Campbell B-K treatment wetlands and ash beneficiation are part of the RAP that is being negotiated with EGLE, with approval expected in early 2025. Removal of ash from the Cobb ash ponds was completed in accordance with an ash removal work plan for which EGLE has provided its agreement. EGLE has agreed that the ash has been removed from the Cobb ash ponds, but under the recently updated Resource Conservation and Recovery Act ("RCRA") rules are indicating that the berms still in place at the site will need to be remediated to obtain final approval from EGLE. The Company will work with the Cobb

site owner to complete an updated site closure plan for approval by EGLE in 2025. The basis of costs for individual work scopes is provided below:

- All Sites Groundwater monitoring – these costs are based on existing third-party costs to collect samples from existing groundwater monitoring systems at each site and to analyze those samples at the laboratory. Costs also include evaluation of the data to determine the potential for a release from the landfill and reporting of the results.

- Weadock Landfill closure scopes of work are well prescribed; the first two years of construction cost were based on contractor bids, and the remaining years are estimated based on similar work that was previously performed at the Karn Landfill. Site-specific items, including importation of additional fill to reach adequate closure grades, have been estimated by third parties and refined based on initial contractor bids. Design for relocating the electric distribution towers that are currently within the landfill footprint is complete with third parties providing cost estimates.

- Karn Landfill Remediation: As described above, this remedial activity has been proposed to the State as part of a RAP, which was accepted by the State in July 2023. The costs reflected represent the selection of a permeable barrier wall, the design of which was completed in 2024 and was approved by the State in early 2025. Costs are based on third-party estimates for similar work.

- Campbell B-K treatment wetlands design is complete, and part of a RAP that is currently being negotiated with the State. Costs for the treatment wetlands are based on third-party estimates for similar work. The ash beneficiation project is part of the RAP currently being negotiated with the State. Costs for this project are based on bids from contractors.

- Campbell deep injection well: Due to the 2024 RCRA rules, the Steam Energy Effluent Guidelines, and the closing of the Campbell plant, a disposal method is required for the leachate from the dry ash landfill. Based on a feasibility study, a deep injection well is the selected alternative. Costs for this project are based on third-party estimates for similar work. Company witness Blumenstock discusses this project in more detail in his direct testimony.

- Cobb 0-8 ash removal was completed, however EGLE has indicated that they will not accept the project as complete without removing the outer berms at the site. Costs for removing the berms are based on high level estimates from third parties for this work.

Q. Please explain the projected coal ash disposal costs.

A. As the Company explained in Case No. U-20849, the projected coal ash closure costs are a result of several changes that have occurred since the Company's previous depreciation case in Case No. U-17653. In April 2015, the EPA published a final rule regulating coal combustion residuals ("CCRs"), such as coal ash, under RCRA. The final rule adopted minimum standards for coal ash landfills and surface impoundments including operational and closure standards, as well as standards for beneficially reusing and disposing of nonhazardous CCR materials. Following the publication of the EPA rule, EGLE determined that more prescriptive state requirements should be established for coal ash facilities to align with federal requirements. In December 2018, EGLE enacted revisions to its solid waste statute for coal ash units and submitted an application for a state permitting program to the EPA for approval.

Q. What is the status of EGLE's application for a state permitting program?

A. The EPA is reviewing the state's application now, but those requirements are already mandated under state statute. Compliance with those new requirements has caused the projected costs to increase. In May 2024, the EPA promulgated new rules regarding historic CCR materials which could impact future costs. Following publishing of those rules, the Company is still reviewing the impact to planned work and revising costs accordingly to comply with the rules. Where impacts are already known, the previous section has addressed in terms of project descriptions. Following the completion of facility

evaluation reports due in 2026, the Company will have further direction regarding impact to planned work and costs.

Q. What were the actual 2024 ash disposal expenditures for Karn?

A. The actual ash disposal expenditures for Karn were $1,448,223.

Q. What were the actual 2024 ash disposal expenditures for Weadock?

A. The actual ash disposal expenditures for Weadock were $19,796,598.

Q. What were the actual 2024 ash disposal expenditures for Cobb?

A. The actual ash disposal expenditures for Cobb were $86,264.

Q. What were the actual 2024 ash disposal expenditures for Whitting?

A. The actual ash disposal expenditures for Whitting were $85,824.

Q. What were the actual 2024 ash disposal expenditures for Campbell?

A. The actual ash disposal expenditures for Campbell were $30,729,863.

Q. Are there potential impacts of changing environmental regulations?

A. Yes. Consumers Energy continues to be subject to environmental regulations that will require the Company to make additional capital expenditures for historical ash closures, groundwater conditions, and effluent treatment, as well as ongoing capital expenditures for maintenance of previously installed equipment. The current and reasonably anticipated state and federal environmental statutes and regulations include but are not limited to: the Steam Electric Effluent Guidelines, Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, the Michigan Mercury Rule, the Clean Water Act Section 316(b), and RCRA, as previously discussed. Consumers Energy anticipates that it will continue to incur costs to comply with the known and unknown environmental conditions that will need to be addressed in a timely manner.

SECTION III

Campbell Units 1, 2, and 3 Decommissioning

Q. Why is the Company decommissioning Campbell Units 1, 2 and 3?

A. The settlement agreement approved by the MPSC in its June 23, 2022 Order in the Company's IRP, Case No. U-21090, approved the retirement of Campbell Units 1, 2 and 3 on May 31, 2025.[2] This retirement aligns with the Company's goal (as approved in its 2021 IRP, Case No. U-21090) to end coal use to generate electricity by 2025, meet Michigan's energy needs while continuing the journey to net zero carbon emissions by 2040, and meet customer needs with 100% clean energy sources by 2040.

Q. Please explain why the Company is presenting actual Campbell Units 1, 2, and 3 decommissioning in this proceeding for the period from January 1, 2024 through December 31, 2024.

A. The Commission-approved settlement agreement in the Company's 2021 IRP in Case No. U-21090 provided for the recovery of actual decommissioning spending for Campbell Units 1, 2, and 3. Specifically, Paragraph 5 of the settlement agreement stated:

> The parties further agree that the Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:
>
> > a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3

[2] On May 23, 2025, the U.S. Department of Energy issued Order No. 202-25-3 ("DOE Order") requiring the Company to "take all measures necessary to ensure that the Campbell Plan is available to operate" through August 21, 2025. The DOE Order also specifies that, at the conclusion of this period, the Company will be permitted "sufficient time for orderly ramp down . . . consistent with industry practices." The Company is currently evaluating the impact of the DOE Order on its decommissioning plan and other aspects of this rate case. Until the Company is able to complete its evaluation, my testimony continues to reflect assumptions about the Campbell Plant's retirement before the date of the DOE Order.

> and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and
>
> b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

In addition, collection of these costs through depreciation rates was terminated in the Company's electric depreciation case, Case No. U-20849. Company witness Daly discusses the establishment of the regulatory asset for these costs and their proposed amortization in his direct testimony.

Q. What information is presented on Exhibit A-141 (JJK-3)?

A. Exhibit A-141 (JJK-3) presents the Campbell Units 1, 2, and 3 actual decommissioning costs for 2024, and an initial estimate for the complete decommissioning of Campbell Units 1, 2, and 3.

Q. What amount of expense for Campbell Units 1, 2, and 3 decommissioning did the Company record to a regulatory asset during 2024?

A. The Company recorded a total of $5,243,744 of Campbell Units 1, 2, and 3 decommissioning expensed to a regulatory asset during 2024.

Q. What is the current estimate for the complete decommissioning of Campbell Units 1, 2, and 3?

A. The current Class 3 budgetary estimate for decommissioning Campbell Units 1, 2, and 3 is $380,000,000. This is an increase of $64,000,000 from the $316,000,000 estimate provided in the Company's 2024 Electric Rate Case, Case No. U-51585.

Q. What contributed to the increase in the estimated cost for Decommissioning Campbell Units 1, 2, and 3 from $316,000,000 to $380,000,000?

A. The items listed in the table below are the major contributors to the increase in the estimate.

Description	U-21585	Current	Delta
AD&D	$148 million	$165 million	$17 million
Project Staffing	$16 million	$25 million	$9 million
Project Indirect Costs	$35 million	$43 million	$8 million
Risk Based Contingency	$36 million	$54 million	$18 million
Recirculation Pond Closure	$0 million	$5 million	$5 million
North Jetty Restoration	$0 million	$3 million	$3million

Q. What activities were accomplished with the $5,243,744 expense for the period from January 1, 2024 through December 31, 2024?

A. Project expenditures in 2024 included $74,742 in Decommissioning cost, $5,043,684 for Project Indirect cost, $197,739 in Interim COR as the result of writing off the cost of projects that were initiated prior to the decision to decommission and will not be completed before the cessation of operations, and a credit of $72,421 for Asset Recovery.

Q. In your opinion, were these costs reasonably and prudently incurred?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes.

MR. GENSCH: Thank you.

Next is the direct testimony of company witness Scott A. McPhail consisting of a cover page and 81 pages of questions and answers. Mr. McPhail also had rebuttal testimony consisting of a cover page and 19 pages of questions and answers and Mr. McPhail sponsored Exhibits A-142 through A-155.

THE COURT: Are there any objections to the direct and -- excuse me. Any objection to the admission of this testimony or these exhibits?

Hearing none. The direct and rebuttal testimony of Scott McPhail is bound into the record and Exhibits A-142 through A-155 are admitted.

(At 3:00 p.m., Exhibits A-142 through A-155 admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

SCOTT A. MCPHAIL II

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Scott A. McPhail II, and my business address is 3201 E. Court St., Flint, Michigan 48506.

Q. In what capacity are you employed?

A. I am employed as Director of Grid Automation by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. In 2008, I graduated from the University of Michigan-Dearborn with a Bachelor of Science degree in Industrial & Systems Engineering. I earned a Master of Business Administration from Eastern Michigan University in 2015.

Q. Describe your experience and current responsibilities at Consumers Energy.

A. I began my career with Consumers Energy full-time in 2003 as an engineering technician, with a focus on gas distribution system design. Over the years I have held various roles involved with economic analysis, revenue recovery, and the Company's Regulatory Affairs department. In 2016, I supported the rollout of the Company's Lean operating system, the Consumers Energy Way ("CE Way"). After supporting a number of business units on the implementation of the CE Way, I joined the Electric Emergency Response team as the Manager. My responsibilities encompassed the preparedness of the Company for storm events that impact the electric grid. I have led many major restoration events for the Company to ensure safe and quick restoration of customers. In April 2024, I accepted the role in Grid Modernization as Director and later changed the name of the department to Grid Automation. The responsibilities in my current role include overseeing the strategy,

deployments (field devices, software systems), and integration of proven technology into business units, providing new capabilities within the Grid Automation portfolio.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony in the following MPSC case:

Case No. U-21585 Electric Rate Case

Q. How is your testimony organized?

A. Below is a Table of Contents outlining my testimony.

I. Purpose and Structure 3
II. Introduction to Grid Automation 5
III. Capital Investments Summary 10
IV. Distribution Circuit Modernization (DCM) Investments 13
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I. Purpose and Structure

Q. What is the purpose of your direct testimony in the proceeding?

A. The purpose of my direct testimony is to provide an overview of the Company's Grid Automation/Modernization plan, and to request approval of the projected capital expenditures to continue the implementation of that plan.

Q. How is the direct testimony structured?

A. **Section I** is the purpose and structure of the testimony.

Section II describes how the Company defines Grid Automation and provides an overview of how modernizing the grid will support the Company's broader electric strategy and the enablement of the foundational capabilities required of a modern grid.

Section III provides an overview of Grid Automation capital investments.

Section IV discusses the Distribution Circuit Modernization ("DCM") investment category.

Section V discusses the Substation Modernization investment category.

Section VI discusses the Electric Distribution Asset Management investment category.

Section VII discusses the Planning Systems Modernization investment category.

Section VIII discusses the Operational Systems Modernization investment category.

Section IX discusses Weather Stations.

Section X provides a closing summary of my testimony.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-142 (SAM-1)	Bridge Period Grid Automation Projects;
Exhibit A-143 (SAM-2)	Test Year Grid Automation Projects;
Exhibit A-144 (SAM-3)	Line Sensor Reliability Benefits;
Exhibit A-145 (SAM-4)	RAMP Reliability Benefits;
Exhibit A-146 (SAM-5)	Line Regulator Controller Upgrades BCA;
Exhibit A-147 (SAM-6)	NOVA TS Comms Reliability Benefits;
Exhibit A-148 (SAM-7)	Peer-Peer Schemes Reliability Benefits;
Exhibit A-149 (SAM-8)	Recloser Modernization Reliability Benefits;
Exhibit A-150 (SAM-9)	Supplemental Line Sensors Reliability Benefits;
Exhibit A-151 (SAM-10)	Metro Modernization Reliability Benefits;
Exhibit A-152 (SAM-11)	Distribution Asset Management BCA;
Exhibit A-153 (SAM-12)	FLISR EPRI Report;
Exhibit A-154 (SAM-13)	FLISR BCA; and
Exhibit A-155 (SAM-14)	Weather Stations Reliability Benefits.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

II. Introduction to Grid Automation

Q. Describe the objectives of Grid Automation and how customers benefit.

A. A core objective of Grid Automation is to reduce the frequency and duration of customer outages. The Company invests in grid infrastructure and adopts technologies proven effective across the utility industry. This often involves upgrading to the latest generation of grid equipment. Over the past several decades, advancements have led to new grid equipment with fewer moving parts, enhanced sensors, and improved communication capabilities, resulting in better performance. The Company's goal is to identify and incorporate these proven, updated grid technologies into its standard deployment programs. The Company has adopted a standardized approach to its deployment called the Technology Enablement Process ("TEP"). This repeatable process benefits customers due to deployment of predictable technologies that improve the customer experience through fewer and shorter outages, and improved power quality.

In the U.S. Department of Energy study titled *Distribution Automation: Results from the smart grid investment grant program*[1] the major findings show that Distribution Automation technologies and systems achieve substantial grid impacts and benefits that meet, and often exceed, pre-project expectations, including:

- Improved fault location, isolation, and service restoration capabilities
- Improved distribution system resilience to extreme weather
- More effective equipment monitoring and preventative maintenance
- More efficient use of repair crews and truck rolls

[1] Office of Electricity Delivery and Energy Reliability. (2016). *Distribution Automation: Results from the Smart Grid Investment Program.* U.S. Department of Energy. https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf

- Improved grid integration of selected distributed energy resources ("DER")

Grid Automation also supports improved power quality for customers by controlling voltage through line conditioning devices. Not only is this needed to meet regulatory standards, but also because improved power quality means customer equipment can operate more efficiently, and the overall power generation supply required is conserved.

The final area of focus is to improve grid safety for the public and our co-workers, such as electric line workers. Consumers Energy's projects aim to leverage automated and remote operations thus reducing hazard exposure of its co-workers and providing quicker response to risks that impact the public.

Q. Why did the Company change the name from Grid Modernization to Grid Automation?

A. The Company saw the need to have a very clear line-of-sight on reducing and eliminating outages that customers experience. Automating the electric grid has been a proven pathway to reach this goal. The future grid is expected to have more automation than ever before, including controlling and optimizing switching devices, voltage regulators, and DERs, to name a few.

Consumers Energy's approach is to not only modernize to next generation equipment, but also to build in automation that improves the customer experience and avoids increased costs. The department will maintain its responsibilities to onboard the latest generation of distribution equipment and systems that are proven in the industry.

Q. Please describe the TEP used at the Company.

A. The TEP is a repeatable approach to design, procure, establish construction standards, including necessary change management efforts, such as policy/process updates, and training in advance of widespread deployment of new technology or equipment.

The TEP methodically works a technology through defined phases, from planning to deployment. Throughout the TEP, the project team will go through the following activities:

- Use case development
- Technology selection validation, operational readiness
- Field implementation

Technologies may build on each other or become *enablers*. Therefore, some projects need to be evaluated as a 'whole' or the 'end state,' whereas other technologies can be evaluated on their individual merits.

This TEP process is used as an initial implementation to later be deployed at scale through the Company's standard Reliability programs, such as those discussed by Company witnesses Jennifer M. Partlan and Megan L. Hayward.

Q. Has the TEP ever resulted against pursuing a new technology?

A. Yes. The TEP is designed to determine if a technology provides customer benefits and is worth pursuing. For example, a phase balancing device was investigated as it was deployed at other utilities to help in situations with a long span of conductor, typically with a large load at the end resulting in phase imbalance. After reviewing customer load data, it was determined the problem this device would address is less of a concern on the Consumers Energy system. Another area explored was a grid edge device that explored the installation

of a device on a transformer pole connected to the secondary conductor. This was aimed at supporting Conservation Voltage Reduction ("CVR") and providing improved power quality for customers. After performing an assessment of these devices installed in the field, it was determined the number of devices that needed to be installed to provide reasonable customer benefits did not provide sufficient benefit to support a large-scale deployment.

Q. What core initiatives comprise the Grid Automation portfolio?

A. The Grid Automation portfolio is comprised of six key pillars of work. These initiatives are:

1. Distribution Circuit Modernization
2. Substation Modernization
3. Distribution Asset Management
4. Planning Systems Modernization
5. Operational Systems Modernization
6. Weather Stations

Each of the six initiatives consists of one or multiple capital investments that are described in detail in the sections below.

Q. How does the Company's Grid Automation plan support the broader electric strategy?

A. Grid Automation is a fundamental part of the electric distribution business. As discussed by Company witness Michael P. Kelly, Grid Automation directly supports the Company's objective of building the grid of the future as the Company installs new technological capabilities on the distribution system. Targeted Grid Automation investments in key areas on the electric distribution system significantly improve safety, reliability/resiliency,

affordability, and enable a clean, equitable grid. The Grid Automation portfolio will continue to deliver on new and improved capabilities through proven technologies, advanced applications, and foundational management systems.

Q. How does the Company's Grid Automation plan support the Company's reliability strategy?

A. Grid Automation is a foundational piece of the Company's Reliability Roadmap alternatively known as the Electric Distribution Infrastructure Investment Plan ("EDIIP"), which is a blueprint to strengthen the Company's electric grid. By enhancing the ability for smart meters, sensors, and automation devices to work together to monitor, isolate, and automatically respond to interruptions more effectively, Grid Automation investments result in reliability, resiliency, and efficiency benefits, including but not limited to:

- Providing voltage optimization to deliver energy efficiently year-round and also reduce energy demand at peak times of the year
- Providing remote monitoring and visibility to see real-time power flow and voltage throughout the grid
- Establishing communication with field devices, enabling real-time load monitoring and fault detection
- Establishing remote control to field devices, enabling real-time settings management
- Enabling remote monitoring and control of field devices to reduce the duration and frequency of outages

As described in each investment's section below, these investments are a core foundation of the Company's long-term plan to improve reliability and resiliency.

Q. Are there any updates to the Grid Automation strategy?

A. Since the creation of the Grid Modernization strategy in 2020, industry trends have changed. For example, the advent of artificial intelligence ("AI") and advancement in

predictive analytics is changing how the utility delivers improved service to its customers. New regulatory requirements are in place, such as Federal Energy Regulatory Commission ("FERC") Order 2222 and Michigan Public Act 235 of 2022 ("PA 235"), promoting more clean generation across the electric distribution system. The Company is revisiting the existing strategy with an emphasis on proven technologies that reduce the numbers and duration of outages that customers experience. The updated strategy will determine how best to sequence investments to enable customers to realize the greatest benefits.

This work will enhance and accelerate the investments already made under the Grid Modernization program and continues to align with the objectives in the Reliability Roadmap.

III. Capital Investments Summary

Q. Please describe how investments are categorized in the Grid Automation portfolio.

A. As discussed by Company witness Kelly, the Company's Grid Automation investments are part of the overall Reliability Program (see Exhibit A-129 (MPK-19). The Grid Automation investments detailed within this testimony fall under six categories: Distribution Circuit Modernization, Substation Modernization, Electric Distribution Asset Management, Planning Systems Modernization, Operational Systems Modernization, and Weather Stations.

Q. Are there investments that are new to the Grid Automation Portfolio?

A. Yes. This testimony will describe a new investment in Remote-Capable Switches within the Distribution Circuit Modernization program and will outline the need for Company Weather Stations.

Q. What is the Company's total projected Grid Automation investment in this case?

A. For the bridge period, the Company projects to spend $25,691,000 as shown in Exhibit A-113 (MPK-3), line 14, columns (i-k). For the test year, the Company projects to spend $17,837,000 as shown in Exhibit A-113 (MPK-3), line 14, column (l). The Company's projected Grid Automation investments are explained in greater detail in the sections below.

Q. Please explain how the capital expenditures will be allocated across the investment categories in the bridge period and the test year.

A. The Company is projecting capital expenditures in the bridge period and test year for each investment category as identified in Figure 1 below.

FIGURE 1
GRID AUTOMATION CAPITAL EXPENDITURES ($000)

	Bridge Period (Jan '25 - Apr '26)	Test Year (May '26 - Apr '27)
Distribution Circuit Modernization	**18,057**	**6,250**
Line Sensors	6,116	-
Voltage Regulator Controllers	10,526	5,120
NOVA TS Comms	20	-
Line Recloser Modernization	135	50
Peer-Peer Automation	895	270
Supplemental Line Sensors	60	115
Metro Modernization	305	650
Remote-Capable Switches	-	45
Substation Modernization	**190**	**375**
IP-Enabled RTU	80	105
IP-Enabled IED	110	270
Distribution Asset Management	**1,740**	**4,050**
Asset Repository	970	1,410
Asset Performance Management	770	2,640
Planning System Modernization	**3,333**	**3,900**
Load Flow Tool Upgrade	3,333	3,900
Operational Systems Modernization	**2,300**	**2,900**
Fault Location Isolation and Service Restoration ("FLISR")	2,300	2,900
Weather Stations	**71**	**362**
Weather Stations	71	362
Total	**25,691**	**17,837**

Q. What has been the historical actual spending in the Grid Automation/Modernization Program for the past five calendar years?

A. The Company's historical calendar year annual spending in the Grid Modernization Program for the past five calendar years is shown in Figure 2 below, and can also be found as shown in Exhibit A-113 (MPK-3), line 14.

FIGURE 2
HISTORICAL GRID MODERNIZATION SPENDING ($000)

Grid Automation Sub-Program	2020	2021	2022	2023	2024
All other Sub-Programs (previously "Grid Modernization: Automation")	43,532	51,153	39,411	25,781	14,596
Advanced Technologies Projects	21,518	23,697	13,934	3,253	5,524
Substation Comm Upgrades	7,214	(696)	(529)	4	42
Total	**72,264**	**74,154**	**52,816**	**29,038**	**20,162**

Q. Please explain the decline in total program spend compared to historical years.

A. Traditionally the Grid Automation/Modernization program included large scale deployments such as Line Sensors and Voltage Regulator Controllers, as shown in the bridge period in Figure 1. The Company expects to complete the deployment of Voltage Regulator Controllers by 2027. Grid Automation investments focus on initial implementation leveraging the TEP described above. Full scale deployments are expected to occur under the Company's traditional programs such as Reliability and Capacity discussed by Company witnesses Partlan and Hayward.

IV. Distribution Circuit Modernization Investments

Overview

Q. Please summarize the objectives of the DCM Initiative.

A. DCM is a Grid Automation initiative integrating and deploying proven technologies commonly used by other utilities that result in improved reliability and increased resiliency on the Low Voltage Distribution ("LVD") and High Voltage Distribution ("HVD") systems. This initiative is made up of two deployment projects and seven TEP projects.

Q. Please explain how the capital expenditures will be allocated across this investment category in the bridge period and test year.

A. The Company is projecting capital expenditures in the bridge period and test year for each investment category as identified in Figure 13below.

FIGURE 3
DCM CAPITAL EXPENDITURES ($000)

Distribution Circuit Modernization Investment Category	Bridge Period (Jan '25 - Apr '26)	Test Year (May '26 - Apr '27)
Deployment Projects		
Line Sensors	6,116	-
Voltage Regulator Controllers	10,526	5,120
Technology Enablement Projects		
NOVA TS Comms	20	-
Line Recloser Modernization	135	50
Peer-Peer Automation	895	270
Supplemental Line Sensors	60	115
Metro Modernization	305	650
Remote-Capable Switches	-	45
Total	**18,057**	**6,250**

Deployment Projects

Line Sensors

Q. Please summarize the objectives of the Line Sensor project.

A. Line sensors are inductively charged devices installed on the overhead primary conductor of the electric distribution system to remotely monitor electrical current, and detect sustained, momentary, and potential faults, thereby improving the capability to respond quickly and reduce customer outages. Figure 4 below is a picture of three line sensors, one installed on each phase of the primary conductor.

FIGURE 4
3-PHASE LINE SENSOR INSTALLATION



Q. What capabilities and benefits do Line Sensors provide?

A. Line sensors provide remote monitoring capabilities that increase situational awareness of the distribution system. This remote monitoring capability and use of real-time data reduces outage durations by providing more transparency and awareness during outage response. Line sensors also benefit the Company during planned outages by providing more accurate historical data for time of day and seasonal loading values.

In addition to fault monitoring, these devices provide critical monitoring capability of equipment that may be nearing its rated capacity.

Line sensor investments provide a variety of reliability and situational awareness benefits. The primary line sensor benefits stem from enhanced fault detection through an increased ability to accurately pinpoint the source of faults or grid disturbances. Line sensor data is monitored in real-time using the AMPLE software and fed to the Advanced Distribution Management System ("ADMS") to identify the location of an outage, enabling faster restoration response.

Line sensors also provide key electric distribution system information such as amperage, conductor temperature, phase balance, mis-phasing, and load flow direction. This data is used to improve the LVD planning process by providing more accurate load flow models and early indication of potentially overloaded equipment. The Load Flow Tool investment discussed later in my testimony will leverage line sensor data to improve the accuracy of load allocation and fault locating capabilities in CYME planning models, illustrating the dependencies these investments have on each other. These enhanced load models are used for capacity, reliability, and DER interconnection planning and to improve the load transfer process for both planned and unscheduled outages within CYME and ADMS.

Fault oscillography provided by line sensors is also used to verify proper coordination between protective devices on the LVD system. The benefits of this remote monitoring capability make line sensors critical to support and enable FLISR, discussed later in my testimony.

The effective integration of line sensors into routine operations will result in avoidance of customer minute interruption ("CMI") estimated at 10,800,000 minutes as shown in Exhibit A-144 (SAM-3). The calculation of CMI is described in Company witness Partlan's testimony.

In addition to the CMI benefits, there are savings associated with the reduction in time related to the crew resources needed to identify and correct faulted conditions on the system. The reduction in the duration of outages for customers decreases their exposure to all the hazards associated with an unplanned outage, including those associated with potential wildfire areas, and wire down conditions when line sensors are installed.

Another line sensor benefit comes from their ability to proactively identify grid disturbances expected to lead to sustained outages. Proactively responding to and repairing grid issues *before* they become an unexpected outage saves the Company costs and avoids customer outages altogether.

In 2022, the Company implemented the Reliability Analytics Monitoring Program ("RAMP") to support predictive fault analytics by analyzing waveforms and data from the existing fleet of line sensors, along with outage ticket data sent to a Cloud Advanced Analytics Platform ("CAAP") software. CAAP is an AI and machine learning platform that builds correlations between specific sensor waveform signatures and outage cause codes, continuously building predictive models that further enhance a line sensor's capability of identifying outages before a customer experiences one.

The primary benefits associated with the execution of RAMP result from proactive actions necessary to correct an adverse condition, whether it be equipment or vegetation related, that if left uncorrected, has potential for resulting in a future outage adversely affecting customers.

Since its implementation, RAMP has identified instances of insulator failures, damaged lightning arrestors, cracked cutouts, and signs of arcing due to vegetation encroachment, resulting in avoided CMI of a total of 136,998 in 2022; 147,488 in 2023; and 181,059 in 2024. As detailed in Exhibit A-145 (SAM-4) RAMP is expected to avoid 2,466,699 additional CMI from 2025 through 2029 with a measurable and direct benefit for customers. The Company has further concluded that additional benefits will be achieved by scaling up the number of line sensors included in RAMP. In addition, there

are avoided costs associated with the proactive identification of adverse conditions by Company employees versus addressing an outage in an unplanned emergent manner.

Q. How are Line Sensor locations selected and prioritized to maximize customer benefit?

A. The first step in selecting line sensor locations is to evaluate and prioritize circuits that are expected to realize the greatest benefit from deploying a network of line sensors. All distribution circuits that do not already have line sensors installed are considered. Circuit characteristics that factor into the prioritization include the historical Customer Average Interruption Duration Index ("CAIDI"), length of overhead miles, number and type of customers, circuit topology, and historical fault events. Once a prioritized list of circuits is established, individual line sensor locations are strategically selected to create zones that enhance predicted fault location precision and FLISR response.

Zones are typically around two miles in length, with sensors placed near non-communicating reclosers, switches, or critical junction points with major load bifurcation. Line sensors may also be installed at special points of interest, such as isolators, large industrial/commercial loads, or areas with dense forestry. This contributes additional benefits by providing monitoring capability to assist in resolving newly identified problems, such as overloaded equipment.

Q. What is the Company's long-term plan for deployment of Line Sensors?

A. The Company has completed deployment of 1,000 line sensors in 2025 on the LVD system, the last year of mass deployment in which the Company expects to complete the deployment with approximately 12,000 line sensors. After 2025, additional line sensors would be added to the system as part of routine reliability and capacity investment projects,

namely in the LVD Lines Reliability, LVD Lines Capacity, HVD Lines Reliability, and HVD Lines Capacity subprograms.

Q. Please identify the projects that will be accomplished with the requested spending level in the Line Sensor investment category.

A. The Company has identified projects for the bridge period, listed in Exhibit A-142 (SAM-1), pages 1 through 2.

Q. What is the Company's projected bridge period spending level, for which it is requesting cost recovery, for the Line Sensors investment category?

A. The Company is projecting Line Sensors capital expenditures of $6,116,000 in the bridge period.

Q. How did the Company develop its projected costs for Line Sensor expenditures?

A. The cost for each location is estimated based on a unit cost that includes known material and unit labor costs associated with purchasing and mounting the sensor.

The estimated number of line sensors per circuit is based on a forecast model using historical sensor deployment data and specific circuit and reliability metrics. The cost for each project is the sum of the costs of each location included in the circuit. The total cost of this investment category is the sum of the individual planned project estimates. In addition to the cost of the devices and installation, the necessary software management system, known as AMPLE, that allows the line sensors to communicate back to the ADMS is included. AMPLE is expected to cost $3,100,000. Lastly, the software cost for RAMP, at $2,083,000, is included in the bridge period. In summary the associated costs are the cost of the line sensor devices, the labor to install the line sensor, the necessary software for the

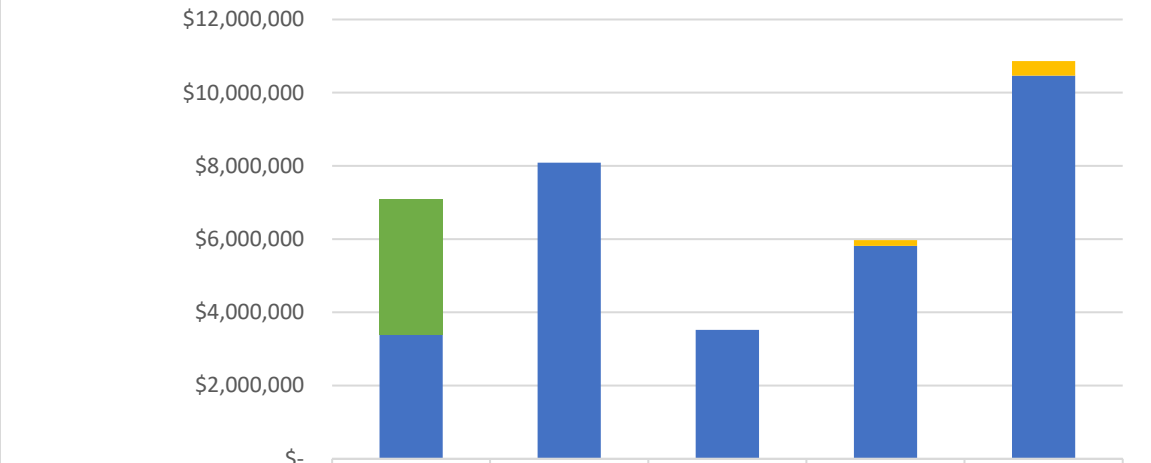
lines sensors to communicate back into the ADMS and the RAMP software to proactively address outages.

If funding is not approved for the AMPLE software, the Company will lose all communications with every line sensor rendering the devices inoperable. The AMPLE software management system is vital to maintain communications with this equipment. In future cases, it is expected this software management system will be a renewal every three-five years to maintain communications.

Q. What has been the historical actual spending for the Line Sensors investment category for the past five calendar years?

A. The Company's historical actual spending in the Line Sensors investment category for the past five calendar years is shown in Figure 5 below.

FIGURE 5
LINE SENSOR 5-YEAR HISTORICAL SPENDING & INSTALLATIONS



	2020	2021	2022	2023	2024
RAMP	$-	$-	$-	$158,000	$395,000
AMPLE Software	$3,702,500	$-	$-	$-	$-
Line Sensor Deployment	$3,394,326	$8,085,793	$3,518,698	$5,811,833	$10,463,581
# of Line Sensors Installed	100	1,700	2,342	2,379	2,979

Q. Please explain year-over-year variation in spending in this investment category.

A. There is a variance in the line sensor project annual expenditures from year to year, primarily due to the timing of when materials are purchased and paid for. In some instances, Line Sensor materials, in part or whole, are purchased near the end of the previous year to support deployment activities scheduled to start the following year. This allows the Company to be more efficient in terms of available crew resources and materials. Line sensor materials can be purchased, delivered, and staged in time to support crew availability and deployment schedules for any particular year. In addition, some of the years may also include the purchase of the AMPLE software management and/or RAMP software, which also contributes to a variance for those particular years. The unit cost for line sensor locations listed in Exhibit A-142 (SAM-1) includes material and labor, but total project cost also includes continuation of AMPLE software management system, as well as RAMP software.

Q. Does average unit cost as calculated in Exhibit A-130 (MPK-20), line 44, accurately reflect the expected spend for an individual unit in this investment category?

A. No. As described in the response above, project costs in this investment category often span multiple calendar years and include costs for multiple year software packages purchased at either a 3-year or 5-year interval. The variance in timing of material deliveries occasionally resulted in two years of material being charged in one calendar year and relatively little material the following year. The material for this investment accounts for more than 75% of the total program cost, and therefore the method of taking the annual cost and dividing it by the annual units completed is not an effective method for

understanding unit cost. Using a blended approach of considering total units and costs over multiple years, levels the unit cost and accounts for the variations described above.

Q. How will the projected Line Sensors expenditures support the key objectives of the Reliability Roadmap?

A. Line sensors reduce the time required to locate faults and provide predictive fault analysis capabilities that then enable the Company to identify and address grid disturbances prior to them becoming a sustained outage, resulting in reduced outages for customers. As covered in the Reliability Roadmap, line sensors directly support proactive fault analytics with RAMP and are an integral part and a key enabler of FLISR, a critical component of the long-term reliability plan. In September 2023, The Liberty Consulting Group ("Liberty") completed their audit of the Company with a review of the Company's Reliability Roadmap.

In the Liberty Report[2] Part II, page 87, number 23, it was concluded that "The planned installation of line sensors is sound." Liberty's justification was explained in the report and is consistent with my testimony on the valid use case for this investment.

Voltage Regulator Controllers

Q. Please summarize the capabilities and objectives of the Voltage Regulator Controllers project.

A. Voltage regulators adjust voltage on the electric distribution system based on changing load conditions to ensure customers receive energy delivered within tariff-specified limits, as indicated in MPSC R 460.3702 (Rule 702). Voltage regulators are remotely connected through the ADMS via a communications-enabled controller, and provide dynamic

[2] Liberty Report Part II - https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000AyKapAAF

remote-control and monitoring capabilities for increased visibility for the Company into the electric distribution system. An example of an upgraded voltage regulator controller is shown in Figure 6.

FIGURE 6
VOLTAGE REGULATOR CONTROLLER



Q. Has the Company performed a Benefit Cost Analysis on Voltage Regulator Controllers?

A. Yes. Please see Exhibit A-146 (SAM-5) in addition to the proceeding explanation. Voltage regulators benefit customers by improving power quality and efficient energy delivery for customers impacted. The dynamic capabilities of the voltage regulator controllers support voltage efficiencies gained through the implementation of CVR and Volt-VAR Optimization ("VVO"). Through the installation of a modem and antenna in the voltage regulator controller, the Company can generate additional MWh savings with this improved visibility and control, as supported by the Department of Energy ("DOE") report

titled *Application of Automated Controls for Voltage and Reactive Power Management*, published in 2012[3].

One of the many benefits of voltage regulator controller deployment is as an enabler of the CVR program, which achieves reduction of energy consumption and peak demand on the electric distribution system. The CVR program and the benefits it provides are discussed in more detail in the direct testimony of Company witness Partlan, as well as the Company's 2021 Integrated Resource Plan ("IRP") in Case No. U-21090, which was settled and approved by the Commission in 2022.

The two-way communication capability also avoids costs by enabling preventative maintenance and proactive replacement of units approaching end-of-life. Proactively replacing equipment prior to failure can prevent customer outages and improve reliability.

The preventative maintenance features also result in the life extension of voltage regulators, further reducing costs. This remote monitoring capability also eliminates the need to perform manual calendar-based inspections, a more costly and timely maintenance method, thus eliminating the need to deploy field crews, which aligns with the DOE's report. By incorporating the ability to remotely monitor and control the voltage regulators with the installation of the modem, the Company saves on cellular costs due to the number of modems, on average, being reduced per location. Most locations only require one modem per voltage regulator controller in lieu of one modem per phase per location because the multiphase controller only requires one modem regardless of how many phases are at the location. The execution of this program has resulted in avoided costs due to the

[3] Office of Electricity Delivery & Energy Reliability. (2012). *Application of Automated Controls for Voltage and Reactive Power Management.* U.S. Department of Energy. energy.gov/sites/prod/files/Voltage%26ReactivePower_Dec2012Final.pdf

replacement of older vintage materials with newer, more efficient materials, thus avoiding the emergent replacement of materials and the potential adverse effects on customer voltage levels.

Finally, this investment benefits the Company's electric line workers through reduced exposure to electrical and traffic hazards. Often these locations are on the side of a roadway, requiring electric line workers to establish a safe work zone. This ability to remotely monitor and operate improves the safety of Consumers Energy's workforce.

Q. How are Voltage Regulator Controller investments selected and prioritized to maximize customer benefit?

A. The Company plans to upgrade all controllers on voltage regulators installed on the electric distribution system. Specific voltage regulator controller locations connected downstream from a Supervisory Control and Data Acquisition ("SCADA")-enabled substation have been prioritized for replacement to align with and support CVR deployment.

Q. What is the Company's long-term plan for deployment of Voltage Regulator Controllers?

A. The Company plans to upgrade 220 regulator locations in 2025 and complete the final year of deployment with 217 regulator locations in 2026. Moving forward, as new locations are added or existing locations replaced, the communicating regulator controller will be the standard installation as part of the Company's reliability programs.

Q. Please identify the projects that will be accomplished with the requested spending level in the Voltage Regulator Controller investment category.

A. The Company has identified projects for the bridge period, and they are listed in Exhibit A-142 (SAM-1), page 3. Projects for the test year are listed in Exhibit A-143 (SAM-2), page 1.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the Voltage Regulator Controllers investment category?

A. The Company is projecting Voltage Regulator Controller capital expenditures of $10,526,000 in the bridge period, and $5,120,000 in the test year.

Q. How did the Company develop its projected costs for Voltage Regulator Controller expenditures?

A. The unit cost for a regulator location is estimated based on material and labor costs associated with the number of phases, and existing health of the location. This is typically driven by three key components:

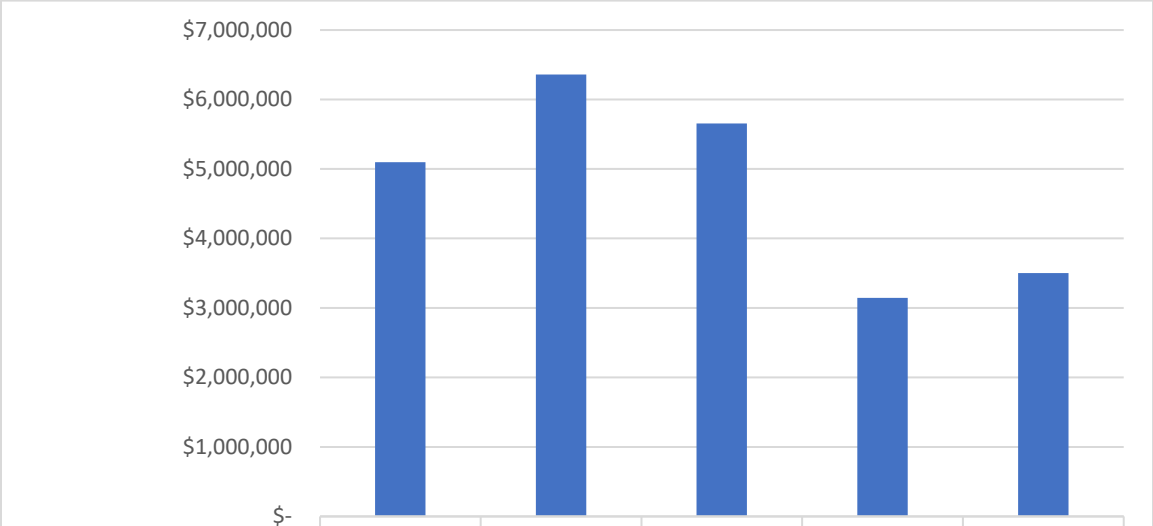
- Voltage Regulator Controller & Communication Hardware – this consists of either a multi-phase control, or one to three single phase controls that allow the remote monitoring and control of the regulators as well as modem(s) and antenna(s).
- Voltage Regulator Pole Top Hardware – based on an inspection, the estimated number of tanks and other equipment that require replacement to gain full functionality at that location.
- Labor Unit Costs are negotiated with the responsible Construction Contractor, and each major work scope component is assigned an individual Unit Cost to more effectively manage, monitor, and control labor costs associated with the construction aspects of the project.

The cost for each work order is the sum of the cost of each location included in the work order. The cost of the investment category is a sum of the cost of all the work orders.

Q. What has been the historical actual spending for the Voltage Regulator Controllers category for the past five calendar years?

A. The Company's historical actual spending in the Voltage Regulator Controllers investment category for the past five calendar years is shown below in Figure 7 and is included in Exhibit A-130 (MPK-20), line 45.

FIGURE 7
VOLTAGE REGULATOR CONTROLLER 5-YEAR HISTORICAL SPENDING & INSTALLATIONS COMPLETED



	2020	2021	2022	2023	2024
Voltage Regulator Controller Deployment	$5,095,218	$6,358,823	$5,654,047	$3,143,732	$3,501,251
# of Controllers Installed	210	162	367	160	156

Q. Please explain year-over-year variation in spending in this investment category.

A. From 2020-2024, the five-year average spending for this investment category is $4.76 million. Variance between years during this period can be attributed to variance in the number of planned locations for each year as well as instances where material is purchased the year before the planned deployment to ensure the most efficient installation and use of available labor resources during the first few months of the following year. In addition, inflationary pressures, especially as they relate to materials, have been an additional factor in this variance from year to year. The Company conducted a competitive

bidding process with respect to Construction Labor for the later years of the project, including 2025 and 2026. As a result of this process the Company has identified a potential cost savings of about $1.5 million with respect to Construction Labor activities related to the project. The potential savings of $3,000 per unit for each location has already been incorporated into the funding request.

Q. Does average unit cost as calculated in Exhibit A-130 (MPK-20), line 45, accurately reflect the expected spend per project for this investment category?

A. No. Project costs in this investment category occasionally span more than a calendar year. Material for this investment is purchased in larger batches, typically several months before the planned installation, to account for procurement long lead times and to ensure material availability for the crews prior to the start of deployment. This allows the project to use dedicated crews with a full complement of material availability. The investment category has seen significant efficiencies and reduced costs using this method of construction. In some years crews are allocated to start this project near or in the first quarter of the year, requiring a significant amount of material be purchased the calendar year before. In other years, deployment is started later in the year and the material is purchased in the same calendar year as the construction. This shift in timing could result in paying for two years of material in one calendar year, and a relatively minimal amount of material the following year. The material for this project accounts for about 50% of the cost, and therefore the method of taking the annual cost and dividing it by the annual units completed is not an effective method of understanding the unit cost. Using a blended approach of considering total units and costs over multiple years, levels the unit cost and accounts for the variations described above. Unit costs are calculated based on historical data, contracted labor, and

material cost across all projects in the investment category without considering calendar year spend.

Q. How will the projected Voltage Regulator Controller expenditures support the key objectives of the Reliability Roadmap?

A. The Company is seeking to improve the efficiency of the electric distribution system by leveraging proven grid technologies, which includes voltage regulator controllers. This investment category is a primary component to enable the Company's CVR plans that have been highlighted in the Company's 2021 IRP. The voltage regulator controller deployment project deploys grid communication equipment, which provides increased visibility into the electric distribution system resulting in improved reliability for customers and serves as a central part of the Grid Automation investment plan, as covered in the Reliability Roadmap. In September 2023, Liberty completed their audit of the Company with a review of the Company's Reliability Roadmap. In the Liberty Report Part II, page 87, number 24, it was concluded that "The voltage regulators the EDIIP proposes are sound." Liberty's conclusion that the "expenditures are moderate and in line with what one can expect for a system like that of Consumers" supports the need for the investment described in my testimony.

Technology Enablement Projects

NOVA Triple-Single Recloser Communications Project

Q. Please summarize the objectives of the NOVA Triple-Single ("TS") Recloser Communications project.

A. The objectives of the NOVA TS Recloser Communications project are to establish an updated technology standard and build on proven technology.

The project aims to add a communications package that can be retrofitted into existing distribution line reclosers' electronic controls, thus saving the expense of replacing the entire recloser. For comparison, a new installation of a communicating recloser (discussed below) can cost over $70,000, but the cost per upgrade site for this project is under $5,000. This standardization enables seamless connectivity with the ADMS. As part of the Automatic Transfer Recloser ("ATR") Loop project, the Company has already upgraded communications for a subset of reclosers connected to the grid. In that project, each ATR controller received a cellular modem. The goal of this project is to extend that successful deployment beyond ATR locations. It aims to provide remote capabilities to NOVA TS reclosers across the system. Leveraging an existing validated design package tailored for NOVA TS reclosers streamlines development. Due to the future unavailability of buying new NOVA TS reclosers, the project is also preparing the new standard SEL 651R controller (similar to the spec used for ATRs) to also be communications capable for all new installs going forward.

Q. What capabilities and benefits do you expect the NOVA TS Communications project to provide?

A. NOVA TS Communications supports situational awareness as follows:

(1) Data can be used by the Company's outage management system to improve restoration processes.

(2) Maintenance can be identified prior to device failures via ADMS alarms, which leads to reduced costs from avoided truck rolls via remote operation.

(3) By bringing this data into the centralized control system, its loading and status data can be used by the power flow application to improve real-time system modeling and monitoring.

These benefits contribute to avoided operating and maintenance ("O&M") spend and increased reliability. This project supports FLISR by providing remote capable reclosers, which are a key enabler of wider FLISR implementation.

This project also supports resiliency because the remote-control capability enables the Company to implement remote load transfers, which prevents truck rolls and reduces the duration of outages for customers. On average, each device is projected to reduce 1,309 customer outage minutes per year via situational awareness and remote closing capability, reducing the duration of outages. Once scaled to the whole fleet of existing reclosers, the reduction of outage duration expected leads to a total avoided CMI of 3,256,577 from 2025 through 2033. These benefits are shown in Exhibit A-147 (SAM-6). This technology can be leveraged for wildfire mitigation at a remote-capable switching location to receive and quickly deploy temporary settings instructions during high-risk events to mitigate the potential for spark generation.

Knowing the current status of the NOVA TS recloser provides a layer of safety for the electric line workers, thus reducing the interaction needed with the device and lowering electrical exposure. When public safety is at risk, the Company receives requests from Emergency Officials such as Fire Departments to isolate sections of the circuit to protect property and the public. This project will provide additional capabilities for the Company's Control Room to remotely perform this request, improving the speed of execution and limiting the number of customers impacted by the request.

The requested investment in the bridge period is not for a full system wide deployment but only the initial implementation of this technology.

Q. How are NOVA TS Communications locations selected and prioritized to maximize customer benefit?

A. The initial locations for this project are chosen to support active needs of the business for a reliability project and facilitate timely field validation at these first upgraded locations.

Q. What is the Company's projected bridge period spending level, for which it is requesting cost recovery, for the NOVA TS Communications investment category?

A. The Company is projecting NOVA TS Communications capital expenditures of $20,000 in the bridge period.

Q. How will the projected NOVA TS Communications expenditures support the key objectives of the Reliability Roadmap?

A. Introducing communications to these reclosers enhances reliability in multiple ways. First, capturing monitoring data enables faster and more confident dispatching when more information about an outage is known, including fault current data for fault location efforts, which reduces outage restoration duration.

Further, remote control capabilities enable time savings via remote close functionality, freeing up electric line workers to continue working on outages while the Control Center expediently restores customers.

Lastly, alarm information enables the Company to attend to abnormal conditions or failures as they occur, which reduces the likelihood of a lingering issue causing an outage or increasing the impact of a nearby outage.

Peer-to-Peer Automation Scheme Project

Q. Please summarize the objectives of the Peer-to-Peer Automation Scheme project.

A. The objectives of the Peer-to-Peer Automation Scheme project are to establish a new standard solution for deploying advanced grid automation schemes, minimize outage impacts, and enable schemes with multiple sources and tie points to react dynamically to system impacts.

In a peer-to-peer scheme, local devices collaborate to determine the optimal sequence to automatically restore customers. Their goals are to minimize outage impacts to as few customers as possible and quickly restore power. This project will develop an advanced control scheme capable of operating with multiple sources and tie points. By doing so, it aims to expand distribution automation systems and identify the locations where they can be deployed. The project has evaluated vendor solutions and will begin its initial implementation in late 2025.

Q. What capabilities and benefits do you expect the Peer-to-Peer Automation Scheme project to provide?

A. The Peer-to-Peer project will support improved reliability by enabling deployment of proven ATRs in new scenarios which can handle complex circuit networks, multiple tie points, load limitations, load transfers, and the increasingly dynamic nature of the grid. These schemes will provide incremental reliability benefits to the ATR deployments discussed by Company witness Partlan. This project will result in reduced customer outage minutes projected at 41% above and beyond the ATR Loop project capabilities (Exhibit A-148 (SAM-7)), which yields an estimated annual avoided CMI at scale of 23,000,000. The project will also support resiliency by providing the Company with a wider range of

alternatives for the ATR Loop scheme selection process; otherwise, fewer future sites will be available in the coming years, leading to fewer ATRs being installed and less customer benefit. This technology can also be leveraged for wildfire mitigation at a remote-capable switching location to receive temporary settings instructions during high-risk events.

Q. How are Peer-to-Peer Automation Scheme circuits selected and prioritized to maximize customer benefit?

A. This project plans to install one initial Peer-to-Peer scheme. The site was chosen to be a critical location to expand distribution automation in an area of high customer density with multiple tie point options and capacity constraints such that no additional automation could have been added using traditional ATR Loop planning. Future deployment will look to prioritize circuits with poor reliability, circuits with a high density of ATRs in close proximity, for which it is difficult to coordinate operations and future expansion, and circuits with ATRs that are already load-limited for transfers to ensure the Company is getting the most out of both new ATR deployments as well as existing infrastructure.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the Peer-to-Peer Automation Scheme investment category?

A. The Company is projecting Peer-to-Peer Automation Scheme capital expenditures of $895,000 in the bridge period, and $270,000 in the test year. It is important to note that the requested investments in the bridge and test period are not for a full system-wide deployment, but only the initial implementation of this technology.

Q. How will the projected Peer-to-Peer Automation Scheme expenditures support the key objectives of the Reliability Roadmap?

A. ATR deployment has proven for many years to be a beneficial investment in reliability and resiliency, as discussed in the Reliability Roadmap. As more ATRs continue to be added to the system, the grid is becoming congested, and a solution for implementing more complex ATR loop networks will be required to drive continued improvements in reliability. This solution for handling complex switching solutions, using real-time loading data to facilitate transfers, will help to ensure future reliability improvements are provided to customers.

Recloser Modernization

Q. Please summarize the objectives of the Recloser Modernization project.

A. The objectives of the Recloser Modernization project are to update the Company standard to industry-established electronic reclosers with a connection to SCADA. Doing so improves reliability via enhanced situational awareness and remote control. This reduces outage time, as well as adds more devices to be used by ADMS in the future. Given the widespread use of hydraulic reclosers across the electric distribution system, implementing this new solution has the potential to significantly improve system visibility and enhance situational awareness.

Q. What capabilities and benefits do you expect the Recloser Modernization project to provide?

A. This project supports reliability by introducing communication to the line recloser fleet, which is foundational to expanding FLISR capabilities, improving outage restoration and response, and improving safe operations by electric line workers. This project supports

situational awareness and safety by providing remote visibility to these line reclosers, which will enable the Company to know the status of devices from the control room and communicate with field workers, reducing the time for outage restoration.

Reduced outage time results in improved reliability for customers and improved customer experience. This project also supports resiliency by enabling remote operations, which will save truck rolls, avoiding costs, and improve reliability via faster restoration by avoiding the need to travel to the device. On average, it is projected each device would yield a reduction of 3,160 CMI. These benefits are shown in Exhibit A-149 (SAM-8). Benefit projections for a future full-scale deployment are estimated avoided CMI of 89,841,549 from 2025 through 2036. This technology will be leveraged in the Company's Wildfire Mitigation Plan at remote-capable switching locations to receive temporary settings instructions during high-risk events.

Q. How are Recloser Modernization locations selected and prioritized to maximize customer benefit?

A. The sites chosen for this project are selected to represent various use cases and construction standards to be encountered in the field to ensure the updated standard is viable across the electric distribution system. These include a combination of necessary phasing and voltage class construction requirements, as well as sites validating the availability of communications to remote rural areas and the usefulness of communication operationally to circuits with longer circuit miles or hard-to-reach areas.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the Recloser Modernization investment category?

A. The Company is projecting Recloser Modernization capital expenditures of $135,000 in the bridge period, and $50,000 in the test year. The requested investment in the bridge and test period is not for a full system-wide deployment, but only the initial implementation of this technology.

Q. How will the projected Recloser Modernization expenditures support the key objectives of the Reliability Roadmap?

A. Recloser Modernization introduces communications to a whole new class of protective device on the distribution system.

Like the other recloser and sensor efforts, the monitoring data provides crucial information usable by electric line workers and the Control Room to assess the scene, reduce patrol time, and enable remote operations to reduce overall outage duration. Having more remote-capable switching devices along main sections and branches of the electric distribution system will greatly increase the ability to enact FLISR, further limiting the outage to customers.

Supplemental Line Sensors

Q. Please summarize the objectives of the Supplemental Line Sensors project.

A. The primary objective of this project is to improve situational awareness of greater parts of the distribution system, enabling improved reliability and operational efficiency. Existing line sensors provide great benefits, but do have some technical limitations—they can measure current and fault data but do not provide voltage, real power, or reactive power

data. Further, there are physical limitations on distribution power lines that prevent them from being installed in certain areas due to low current. As updates to this technology continue to evolve, this project will incorporate the latest industry devices and tactics.

The project's timeline has been synchronized with the end of the existing line sensor rollout to ensure alignment with technological advancements and industry best practices.

Q. What capabilities and benefits do you expect the Supplemental Line Sensors project to provide?

A. Line sensors currently provide significant reliability benefits, but there are limitations to the types of circuits that benefit most from the existing sensor solution. There are also constraints as to how many line sensors can be placed in certain locations. This project will support situational awareness by introducing the potential for enabling additional grid locations or to improve the type of data captured; and through providing more grid data into the Company's ADMS system, situational awareness is improved for power flow and outage management systems and leads to incremental reliability benefits, which reduces customer outage duration. This project also supports further FLISR functionality with additional locations of sensors, which would provide enhanced fault locating, improve outage response via FLISR to increase reliability benefits, and further shorten customer outages. Projected benefits are shown in Exhibit A-150 (SAM-9), with estimated avoidance of 13,751,914 CMI from 2025 through 2033. This benefit would occur once deployed on the remainder of circuits that don't have the existing line sensor solution installed.

Q. How are Supplemental Line Sensors locations selected and prioritized to maximize customer benefit?

A. The initial locations for this project will be selected based on the inability of circuit conditions to host the Company's present line sensors. Location selection will be balanced with areas benefiting from increased data collection capabilities for both current and voltage.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the Supplemental Line Sensors investment category?

A. The Company is projecting Supplemental Line Sensors capital expenditures of $60,000 in the bridge period, and $115,000 in the test year. It is important to note that the requested investments in the bridge and test periods are not for a full system-wide deployment but only the initial implementation of this technology.

Q. How will the projected Supplemental Line Sensors expenditures support the key objectives of the Reliability Roadmap?

A. Building on the foundational benefits of the current Line Sensor project, as described in the Reliability Roadmap, this project will provide improved visibility to circuits with poor reliability that are not viable candidates for the current deployment as explained in the Line Sensors project section above. Doing so improves fault location efforts and reduces restoration time.

Metro Modernization

Q. Please summarize the objectives of the Metro Modernization project.

A. The Company's Metro system provides necessary power to many downtown urban areas through a network of underground vaults. Company witness Hayward provides a more detailed explanation of this critical infrastructure. The Metro Modernization project objective is to provide technology options for upgrading to an advanced Metro vault standard. Doing so will yield improved customer reliability, operational cost savings, and Metro integration into ADMS. In pursuit of this, the project will evaluate several areas: use of specialized sensors designed to detect water or gas hazards within the Metro system, assessment of switching equipment enhancements to enhance reliability and efficiency, development and integration of a communications package to facilitate seamless data exchange, and investigation of remote-control capabilities to streamline Metro operations. By establishing an updated Metro standard, the project will elevate critical electric infrastructure to industry best practices, leveraging the latest technological advancements.

Q. What capabilities and benefits do you expect the Metro Modernization project to provide?

A. Bringing vaults to a new standard that includes communication and sensing solutions enables safer and more effective operations. This project supports situational awareness by introducing monitoring and control capabilities into metro vaults, which reduces operational costs via remote operation with easier maintenance of switching equipment. Added visibility to equipment health enables proactive maintenance and inspection prior to larger failures and would lead to a further reduction in costs. This project also supports reliability by speeding up operations and outage restoration, providing shorter outages for

customers. Projected benefits are shown in Exhibit A-151 (SAM-10) reporting avoided CMI; while the CMI component may seem small, the Metro system hosts a disproportionately larger percentage of commercial and priority customers such that reducing otherwise exceedingly long outages on the Metro system significantly impacts the customer experience. Further, there is a meaningful reduction in work hours totaling 185 hours of exposure to dangerous confined spaces to electric line workers when all vaults become upgraded in the future. The improved safety benefit for Company electric line workers alone necessitates this modernization investment.

Q. How are Metro Modernization locations selected and prioritized to maximize customer benefit?

A. This project will target one to two vaults to upgrade initially. These sites will be chosen based on use cases of likely site types typical of the Metro system. The use cases that will drive site selection include sites subject to flooding and/or gas leaks to benefit from environmental detection sensors to improve field worker safety, as well as sites of operational importance to receive upgraded switching devices and a method to communicate back to the Control Room through SCADA. It is also of note that many of the Metro systems statewide all serve high-scoring environmental justice ("EJ") communities such that all Metro investments associated with this project and future deployments will be providing a positive impact for those communities.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the Metro Modernization investment category?

A. The Company is projecting Metro Modernization capital expenditures of $305,000 in the bridge period, and $650,000 in the test year. The requested investment in the bridge and test period is not for a full system-wide deployment, but only the initial implementation of this technology.

Q. How will the projected Metro Modernization expenditures support the key objectives of the Reliability Roadmap?

A. Providing visibility and remote-control access to Metro vaults will yield valuable operational capabilities to improve reliability. Like the other projects preceding it, Metro Modernization will introduce additional switching devices brought to a new standard with communication. Enhanced remote and local control options will speed operations and restoration. The monitoring of devices and hazard sensors also can contribute to proactively addressing issues before they lead to catastrophic failures, thus avoiding unnecessary equipment failure outages. Finally, introducing smart and communicating equipment in vaults sets the stage for future automation schemes involving the Metro system, and integration with FLISR and ADMS switching solutions—all of which positively affect reliability of the Metro system, which is described in the Reliability Roadmap.

Summary

Q. Please summarize how the investments described above in the DCM Initiative support the overall electric strategy and the Reliability Roadmap.

A. Described throughout the DCM Initiative and as stated in the Reliability Roadmap, there is a focus on reducing the number and duration of outages that customers experience. The Company has a standardized approach to begin deployment of proven industry technologies through its TEP. Each project shows the avoidance of CMI while improving the safety for the Company's front-line co-workers and the public.

V. Substation Modernization Investments

Overview

Q. Please summarize the objectives of the Substation Modernization ("Sub Mod") Initiative.

A. Sub Mod is a Grid Automation initiative with the primary objective of deploying advanced distribution substation technologies and updating the necessary communications within the substation. These technologies are intended to align with and enable current and future Grid Automation initiatives such as DCM, ADMS, and the increased penetration of DER. This initiative will identify and prioritize solutions that provide adaptability, interoperability, security, resiliency, and reliability to grid operations to support the grid of the future.

Sub Mod will support a future where the Company has enabled modernized communications, provided network capabilities, enhanced control infrastructure with distributed intelligence, coordinated intelligent devices and automation schemes, improved system visibility with robust data collection, and improved cyber and physical security.

Q. Please explain how the capital expenditures will be allocated across this investment category in the bridge period and test year.

A. The Company is projecting capital expenditures in the bridge period and test year for each investment category as identified in Figure *1*8 below.

FIGURE 8
SUBSTATION MODERNIZATION CAPITAL EXPENDITURES ($000)

Substation Modernization Investment Category	Bridge Period (Jan '25 - Apr '26)	Test Year (May '26 - Apr '27)
IP-Enabled RTU	80	105
IP-Enabled IED	110	270
Total	**190**	**375**

IP-Enabled Remote Terminal Unit

Q. Please summarize the objectives of the Internet Protocol ("IP")-Enabled Remote Terminal Unit ("RTU") project.

A. The objective of the IP-Enabled RTU project is to overcome the limitations associated with the existing serial-based RTU hardware and network design used by the Company by enabling IP communications and integrating Field Area Network ("FAN") equipment. Currently, the RTU faces technical challenges such as (1) remote monitoring and management (i.e. the inability to monitor, manage, and maintain the RTU remotely impacting both cybersecurity and day-to-day operations), and (2) design complexity (i.e. existing design limitations necessitating additional wiring for collecting substation data, leading to increased cost and complexity). Serial technology is now becoming increasingly antiquated, and the industry is moving away from supporting that communication standard to Intelligent Electronic Devices ("IEDs"). Previously, the Company had to address and upgrade modem standards during the 3G sunset, and it is only a matter of time before serial technology also becomes unsupported in the industry and

severely limiting technology options to better serve customers. To address these issues, the project has introduced hardware and configuration changes that have undergone rigorous testing in a controlled lab environment. These tests covered operational functionality, cybersecurity, interoperability, and engineering functionality. Having successfully completed lab testing in 2023, the project is now ready for targeted field deployment at two initial locations in 2025.

Q. What capabilities and benefits do you expect the IP-Enabled RTU project to provide?

A. The IP-Enabled RTU project will bring digital communications to the substation, setting up the framework for the IP-Enabled IEDs and Common Substation Platform. These units enable the delivery of the following capabilities for upgrading distribution substations:

- Data Network Security
- Improved Operator Efficiency
- Enhanced Situational Awareness
- Standards Based Designs and Data Communications
- Remote Engineering Access
- Configuration & Firmware Management

Ultimately, not pursuing this enhancement will leave critical substation communications infrastructure stuck with antiquated serial protocols that may lead to increased incompatibilities with modern hardware, and a potentially costly and/or urgent need to update on a less convenient and more aggressive schedule if establishing this deployment is deferred. A safety benefit is the reduced electrical exposure at high voltages for the Company's front-line work force. Today, electric substation workers must enter into the substation fencing to perform their tasks of updating firmware and adjust settings. Remote

Engineering Access through this device will eliminate the need to perform those tasks onsite.

Q. How are IP-Enabled RTU locations selected and prioritized to maximize customer benefit?

A. The initial deployment locations were selected to confirm the capabilities described above and to be locally accessible to the resource groups in Jackson, MI. These locations represent distribution substations with a current standard RTU that supports remote engineering, automated monitoring, and cyber security requirements. Additional consideration was given to locations where the SCADA cabinet included ample space for the additional FAN communications equipment.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the IP-Enabled RTU investment category?

A. The Company is projecting IP-Enabled RTU capital expenditures of $80,000 in the bridge period, and $105,000 in the test year. It is important to note the requested investment in the bridge and test period is not for a full system-wide deployment, but only the initial implementation of this technology.

Q. How will the projected IP-Enabled RTU expenditures support the key objectives of the Reliability Roadmap?

A. IP-Enabled RTUs are the first foundational technology enhancement to substations that will be built upon in the coming years. Once fully realized, the capabilities of the substation of the future will provide benefits to many areas including reliability, grid security, and safety. As the devices on the electric distribution system become smarter and more interconnected, it is crucial that distribution substations keep up with that trend and can be

an important part of the integrated solutions to come. This project is a critical first step to achieving that capability.

IP-Enabled IED

Q. Please summarize the objectives of the IP-Enabled IED project.

A. The objective of the IP-Enabled IED project is to overcome limitations associated with the existing hardware and network design of additional IEDs.

An IED can include regulators, reclosers, and transformer bank monitoring equipment. These IEDs currently lack the capability to connect and communicate over IP networks, which hinders their integration into the FAN. This TEP project will deploy new hardware into the substation allowing the communication of IEDs back into the Control Room and across Engineering departments.

Q. What capabilities and benefits do you expect the IP-Enabled IED project to provide?

A. This project builds on the infrastructure set up in the IP-Enabled RTU project. There are additional data points and logs available within the substation devices that cannot be pulled remotely now or even through an upgraded RTU.

A major benefit to IP-enabled IEDs is that retrieval of this information will be instantaneous and avoids the cost and risk of dispatching an electric substation worker to the substation site to download the information, reducing truck rolls and improving co-worker safety. Similar to IP-Enabled RTUs, a safety benefit is the reduced electrical exposure at high voltages for the Company's front-line work force. Today, Utility Workers must enter the substation to perform their tasks of pulling log data. With a FAN established, as detailed in the IP-Enabled RTU section, Remote Engineering Access is available. This will eliminate the need to perform those tasks onsite.

Q. How are IP-Enabled IED locations selected and prioritized to maximize customer benefit?

A. The IP-Enabled IED project plans to use existing IP-Enabled RTU locations. This approach provides the Company with the opportunity to integrate learnings from both projects and demonstrate use case capabilities and continuity. These locations represent a large (six distribution circuit) and a smaller (two distribution circuit) substation with multiple current standard control types that will support remote engineering, automated monitoring, and cyber security requirements.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the IP-Enabled IED investment category?

A. The Company is projecting IP-Enabled IED capital expenditures of $110,000 in the bridge period, and $270,000 in the test year. It is important to note the requested investment in the bridge and test period is not for a full system-wide deployment, but only the initial implementation of this technology.

Q. How will the projected IP-Enabled IED expenditures support the key objectives of the Reliability Roadmap?

A. This project will provide immediate access to logs, event data, and other detailed information concerning substation equipment to enable predictive failure analysis. The ability to perform analysis in real-time based on data across key substation equipment will enable the identification of imminent failures or the need for repairs *before* an outage occurs. It also enables faster diagnosis into the reason for failures during an outage. Both will reduce or eliminate outages related to substation equipment, and will reduce costs and large-scale customer outages that stem from emergent repairs.

Summary

Q. Please summarize how the investments in this category support the overall electric strategy and the Reliability Roadmap.

A. The Sub Mod initiative is a foundational enabler of multiple other Grid Automation projects. With the rise of DER, electric vehicles ("EVs"), and grid-edge communication, it is important and necessary to upgrade core systems to be able to integrate, translate, and communicate with the growing amounts of data.

IP-enabled communication with grid critical assets provides future flexibility and ensures strong physical and cyber security. Technology deployments, like those outlined in this section, are critical to delivering benefits for current Grid Automation work, such as the suite of DCM projects and for future efforts related to DER optimization.

VI. Electric Distribution Asset Management

Overview

Q. Please summarize the objectives of the Electric Distribution Asset Management ("DistAM") Initiative.

A. DistAM is the application of asset management principles and processes to electric distribution assets to maximize the usefulness and realization of value over their lifecycle, resulting in improved reliability through reduced equipment failure.

DistAM will develop lifecycle management capabilities by collecting key asset data (e.g. age, nameplate data, location, work orders) to drive a risk-informed, value-based decision-making methodology to manage and optimize asset investments. The components within DistAM will collect distribution asset data into a single centralized

database that provides enhanced integration into asset health performance analysis, and investment strategy platforms.

Key objectives within DistAM are to improve the Company's capital efficiency and asset maturity levels. With increased asset maturity we will leverage advanced risk analytics to create asset health scores, essential for optimizing investment planning scenarios, and addressing outages before they happen. This work is aligned with industry best practices defined in ISO 55000(1), as well as from the Michigan Infrastructure Council Asset Management Program.

Q. Please describe the DistAM Approach.

A. The Company developed a DistAM strategy with key workstreams: Asset Repository ("AR"), Asset Performance Management ("APM"), and Asset Investment Planning ("AIP") (now complete).

Utilities without a structured asset management approach still accomplish ad hoc and reactive asset management tasks; however, this stopgap approach will not provide the same customer benefits and desired system performance. Rather, it will continue to drive increased system costs based on the lack of capability for data-driven decisions and planning.

DistAM is distinct from ADMS because it focuses on the lifecycle asset management rather than real-time operational management of assets. Asset management typically requires data that is collected and visualized over long-time scales. Consequently, DistAM informs decisions over the medium-to-long term as opposed to ADMS's short-term operational decision-making.

Q. Please explain how the capital expenditures will be allocated across this investment category in the bridge period and test year.

A. The Company is projecting capital expenditures in the bridge period and test year for each investment category as identified in Figure *1*9 below.

FIGURE 9
DISTRIBUTION ASSET MANAGEMENT CAPITAL EXPENDITURES ($000)

Distribution Asset Management Investment Category	Bridge Period (Jan '25 - Apr '26)	Test Year (May '26 - Apr '27)
Asset Repository	970	1,410
Asset Performance Management	770	2,640
Total	**1,740**	**4,050**

Q. How much has the Company invested in the DistAM program to date?

A. Since the launch of DistAM, the Company has invested $7.9 million as of March 31, 2025. The AIP was launched in 2024 and consisted of $5.8 million. Since the launch of this project, $2.1 million has been spent on the AR and nothing has been spent on the APM as of March 31, 2025. The Commission originally approved the DistAM project in Case No. U-20697 and re-approved in the December 22, 2021 Order in Case No. U-20963. The concept approval at that time projected an estimated $12 million for the project. This is the amount the Commission discussed in its Case No. U-21585 Order, stating that approval of increased costs would require updated data.

Q. How much is the Company proposing to spend on the DistAM program through the test year in this case?

A. Including the prior investment through the test year, the Company's current total projected spend for the DistAM program is $13.6 million.

Q. Please explain why costs have increased from the original projected $12 million for this project.

A. Through the purchase and implementation of the AIP in 2024 and continued build out of the AR, more refined costs are now known to build a DistAM solution. As the project advanced, the Company discovered the need for the expansion of additional IT applications that were not initially scoped. Reviews were conducted on the quality of the Company's data and determined it would not meet the requirements of a vendor provided solution for an APM. The initial approach of the Company was to purchase the APM solution and implement similar to the AIP. However, as the Company's asset maturity continues to improve, it was deemed a better value to build an internal APM solution that will meet most of the requirements. It is estimated a vendor provided solution for an APM would cost $7.5 million to implement in year one with an estimated $1 million annual software as a solution agreement. Instead, the Company will build its own APM, estimated at $4.2 million with no software agreement cost. As assets are brought into the AR, this internal APM will be able to accommodate each new asset as it becomes available. My testimony below will describe in more detail what is left to complete within the test period with regard to AR and APM.

Asset Repository

Q. Please summarize the objectives of the AR.

A. The AR provides a single, centralized database to store essential distribution asset data. The AR identifies and structures asset relationships including asset grouping, parent-child relationships, and organization hierarchies. For example, it can identify the relationships between a voltage regulator, the voltage regulator controller, and the cellular modem so

these three components can be evaluated (risk-assessed) together. Grouping related equipment drives cost efficiencies by ultimately allowing for the bundling of work at the same locations. Maintaining an AR facilitates sharing of asset information across multiple software, systems, and third-party applications. A major component of the implementation of an AR is the software and data integration. The AR provides the APM and the AIP tools a single source of truth for asset information eliminating redundancy and inaccuracy. Along with the software and data integration, the AR also has the objective to collect comprehensive and accurate data on major electric distribution assets. Drone flights and imaging have been added to collect the comprehensive and accurate data on distribution assets across select circuits.

Q. What capabilities and benefits do you expect the AR to provide?

A. DistAM is an essential part of the Company's broader initiative to maximize reliability and resiliency by optimizing how the electric distribution system is proactively maintained and managed. The AR enhances the Company's asset life-cycle processes, data, imaging, and technology, allowing for improved capture and analysis of asset health details, which will lead to more optimized investment planning scenarios. The primary benefits of DistAM include:

- Reduced capital and maintenance costs
- Reduced customer outages and restoration costs
- Reduced power quality issues and system losses
- Increased asset availability
- Reduced asset degradation risk
- Improved resilience of the electric distribution system
- Improved asset maturity

- Imaging

A centralized asset repository improves work efficiency by avoiding the need to manage across various software to pull and analyze data. In addition to improved efficiency, this tool provides the ability to complete advanced risk analytics to create asset health scores. The benefits of the AIP and APM would not be fully realized without a robust asset repository feeding consistent, comprehensive data. DistAM will use smart grid technologies to effectively coordinate the use of devices, the data they consume, and the information they produce, supporting all other Grid Automation capabilities in delivering benefits to customers.

A comprehensive BCA is provided for the DistAM as a whole in Exhibit 152 (SAM-11), including all necessary components of AR, APM, and AIP.

It is important to note the analysis performed in the BCA is on the full implementation of DistAM across all in-scope electric assets. The requested investment in the bridge period and test year does not include the full system costs. Future rate cases will request the needed funding to complete the full implementation of this technology. Exhibit A-152 (SAM-11) contains the estimated total costs across the life of the DistAM program.

Q. What electric distribution assets will be considered within the AR?

A. The AR will consider all major electric distribution assets on both the HVD system and LVD system. Examples of the assets that will be considered in the AR include:

- Equipment installed on the Company's HVD lines, including but not limited to poles, switches, insulators, and conductors;
- Equipment installed within distribution substations, including but not limited to transformers, regulators, reclosers, breakers, and relays; and
- Equipment installed downstream from the distribution substation fence, including but not limited to poles, conductors, transformers, capacitors, voltage regulators, metro equipment, and isolators.

In total, seven electric assets are planned to be included by the end of 2025 with a total of 19 assets planned for by the end of 2027.

Q. How will assets be selected and sequenced to maximize customer benefits?

A. The Company plans to integrate an array of distribution assets into the AR, APM, and AIP over time. These assets will be added in an iterative fashion to reduce complexity and use learned efficiency gains. The Company will use several metrics to sequence the order assets are integrated to help maximize customer benefits.

Three primary metrics will be used to sequence asset integration: customer and reliability impact, data availability, and complexity. These metrics help describe the Company's asset maturity.

> Reliability Metric: The reliability benefit metric will be used to consider the amount of value generated by improving asset management practices for the asset. Assets with a high reliability benefit have a significant impact to system reliability and customer outages if they fail or perform poorly.
>
> Data Availability Metric: The data availability metric considers the availability of high-quality data that can be used to evaluate asset health. Assets with limited data will be more difficult to integrate and optimize.
>
> Complexity Metric: The complexity metric is used to consider the quantity and difficulty with technically integrating asset data from various source systems into the AR. Some assets will require data from many diverse systems to develop an accurate health score, while other assets may be evaluated with a limited number of simple integrations. Likewise, the quantity of assets and their associated data points may vary from hundreds to thousands to millions with escalating complexity.

By evaluating each asset and scoring it based on these evaluation metrics, the Company has developed an asset integration strategy that maximizes customer benefits.

Q. How will the projected expenditures support the key objectives of the Reliability Roadmap?

A. The AR is the foundational component of the broader DistAM strategy. To enhance the ability to proactively monitor and replace assets prior to creating an outage, the Company

needs a system that tracks and structures the data in a methodical approach. The AR provides that standardization and is an enabler of the many beneficial reliability programs that follow, including AIP and APM. As covered in the Reliability Roadmap, the DistAM program is an essential part of the Company's broader initiative to maximize reliability and resiliency by optimizing how the electric distribution system is proactively maintained and managed to increase reliability for customers.

Asset Performance Management (APM)

Q. Please summarize the objectives of APM.

A. APM encompasses the capabilities of data capture, integration, visualization, and analytics tied together to improve the reliability and availability of physical assets. The APM is a software tool that leverages the base of asset data made available from the AR to develop a health index or a health score for assets across electric distribution. This tool will use advanced algorithms to develop health and risk monitoring through a standard and common interface for Company employees to generate, monitor, and make decisions for identifying opportunities to address assets requiring attention based on asset health and risk. It is expected that these asset health and risk scores will be incorporated into the Company's Quarterly Operating Review ("QOR") as discussed by Company witness Kelly.

Q. What capabilities and benefits do you expect APM to provide?

A. APM will enable the Company to monitor asset health and risk enabling reliability-centered maintenance. It is a systematic approach to the delivery of business objectives, including:

- Improvement of the reliability and availability of physical assets
- Minimization of risk of asset failure, downtime, and operating costs

- Provisioning or enhancement of condition monitoring
- Enablement of predictive maintenance
- Health and Risk Models

Developing APM capabilities will provide improved visibility and targeted identification of assets that are higher risk, which can be prioritized as part of a maintenance or replacement strategy. A reduction in asset failures will reduce unplanned outages, which results in a reduction of emergent work, customer outage minutes, and associated costs. Improved visibility and analysis of health of assets also leads to more efficient deployment of power quality and energy delivery.

By proactively replacing assets prior to their anticipated failure, the Company expects to save costs on material and labor. Emergent asset replacements typically have higher costs compared to traditional replacement work as they may occur during nonbusiness hours, and the Company would not have materials staged and ready for delivery.

A comprehensive BCA is provided for the DistAM as a whole in Exhibit 152 (SAM-11), including all necessary components of AR, APM, and AIP.

It is important to note that the analysis performed in the BCA is on the full implementation of DistAM across all in-scope electric assets. The requested investment in the bridge year and test period does not include the full system costs. Future rate cases will request the needed funding to complete the full implementation of this technology.

Q. Please describe the work to be accomplished in the development of the APM through the test year.

A. Company Data Scientists will design and test the necessary algorithms to produce a health score with its associated risk. Depending on the type of asset and available data, a different algorithm may be necessary to produce its own unique health score. As additional assets are added into the AR, necessary database connections will be established to ensure the correct association from the asset to its unique algorithm for processing.

Q. How will assets be selected and sequenced to maximize customer benefits?

A. The Company will prioritize assets following the same methodology as explained in the AR section above. Prioritization will primarily be based on customer and reliability driven impacts. All assets with a minimal level of data availability, even as simple as the date installed, can be considered for analytics in the APM tool. Once an asset has gone through the AR roll out, the Company expects to be able to optimize the health and risk assessment through its QOR.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the APM investment category?

A. The Company is projecting APM capital expenditures of $770,000 in the bridge period, and $2,640,000 in the test year.

Q. How will the projected expenditures support the key objectives of the Reliability Roadmap?

A. The APM tool standardizes the Company's centralized approach for managing assets. The tool will directly impact reliability by improving the Company's processes around calculating and visualizing asset health to ensure the most critical projects are given the

highest priority. This optimized prioritization will reduce the number of emergent failures and unplanned outages, improving reliability for customers. As described in the Reliability Roadmap, the APM aims to improve reliability through a reduction in emergent outages.

Summary

Q. Please summarize how the investments in this category support the overall electric strategy and the Reliability Roadmap.

A. DistAM directly supports the Reliability Roadmap's objectives of reliability, system cost, and sustainability. By capturing and maintaining asset data and using it for data-driven decisions, the Company can reduce costs and improve asset reliability. As discussed in the Reliability Roadmap, data and analytics are becoming increasingly critical to inform long-term investment decisions, and to drive continuous improvement of electric distribution system operations. DistAM is an essential part of the Company's broader initiative to maximize reliability and resiliency by optimizing how the electric distribution system is proactively maintained and managed. DistAM will enable the Company to develop and manage asset health conditions on the electric distribution system to optimize asset performance, control costs, and allow the Company to provide a more comprehensive overview of its system in future distribution plans.

In September 2024, Liberty completed their audit of the Company with a review of the Company's Reliability Roadmap. In the Liberty Report Part II, page 87, number 26, it was concluded that "The EDIIP's proposal for creation of DistAM comports with our recommendations about enhancing asset management." Liberty's conclusion that the "system appears designed to support a programmatic, analytically founded, and data driven

asset management strategy, all of which are in keeping with our recommendation." This further supports the need for the investment described in my testimony.

VII. Planning Systems Modernization

Overview

Q. Please summarize the objectives of the Planning Systems Modernization Initiative.

A. The Planning Systems Modernization initiative is dedicated to researching, developing, and demonstrating desired future state technologies and solutions to integrate into the Company's planning framework. This initiative takes a comprehensive and holistic view of the electric business's planning steps and processes to assess improvement opportunities and recognize future state requirements. The goals of the Planning Systems Modernization initiative are to: leverage technological advancements to generate new or improved datasets that optimize performance of planning tools, enable new tool functionality to meet evolving business needs, specifically towards the integration of DER, and consider interdependencies with other Grid Automation initiatives to support cross-functional use cases. Currently the Planning Systems Modernization initiative is comprised of a technology upgrade to the existing Load Flow Tool necessary to maintain regulatory compliance and to conduct accurate grid modeling.

Load Flow Tool Upgrade

Q. Please summarize the objectives of the Load Flow Tool Upgrade.

A. The Load Flow Tool Upgrade seeks to modernize the Company's planning processes and tools by developing new functionalities within and alongside the CYME power engineering software, which has been a cornerstone for utility planning departments for nearly 25 years. As discussed in the Reliability Roadmap and the below testimony, the current planning tool implementation requires an overhaul to allow the Company to meet regulatory

expectations related to the fast track initial and supplemental DER review screens, Michigan Transportation Electrification Plan, hosting capacity map enhancements, and the increase in the Distributed Generation program cap. It will also enable the Company to remain capable of proactively addressing the evolving challenges and opportunities associated with increasing DER penetration and electrification on the distribution system.

Key components of the upgrade are expected to include, but are not limited to:

- Selection and implementation of an industry standard forecasting tool capable of producing hourly, weather normalized load forecasts under alternate future DER and load growth scenarios.
- Enabling time-series load flow simulations in the CYME software using historical AMI, MV90, and SCADA data or the forecasted load data above.
- Leveraging CYME's Advanced Project Manager module and as-planned network model to enhance collaboration, communication, and prioritization of distribution system upgrades.
- CYME Gateway enhancements to automate the import of existing DER interconnections into the CYME as-built network models.
- Integration with PowerClerk and/or SAP to include queued but not yet commissioned DER interconnection requests in the as-planned network model.
- Integration with SAP to include detailed project scope, milestones and costs into the CYME as-planned network models.
- Development of automated solutions to enable comprehensive review of the fast track initial and supplemental review screens specified in R 460.946 and R 460.950 of the Michigan Interconnection and Distributed Generation Standards.
- Enhancements to the Company's future load and generation hosting capacity maps recommended by the MPSC's September 8, 2022 Order in Case No. U-20147; the Distribution System Data Access workgroup and June 30, 2023 Grid Integration Study filed in Case No-21251; and the March 1, 2024 Order in Case No. U-21389.

In 2024, the Company entered a CYME Advanced Distribution Planning System Discovery project to further define the scope, data requirements, technical requirements,

high-level cost, and projected timeline of the above objectives. The final report from this effort is expected to be available by July 2025, with an optimally sequenced implementation beginning in the bridge period of the current case.

Q. What capabilities and benefits do you expect the Load Flow Tool Upgrade to provide?

A. The Load Flow Tool Upgrade will enable time-series load flow simulations in CYME. Current load modeling and allocation practices account for a single snapshot in time of peak loading conditions and cannot accurately or efficiently address the intermittent behavior of DERs and electrification. Expected benefits of integrating historical, and forecasted time-series datasets with the planning tool include:

- Significantly increased model accuracy and precision
- Reduction in model development time due to enhanced load allocation
- Proactive mitigation of voltage anomalies resulting in a reduction of customer complaints
- Expedited resolution of customer complaints when they do occur
- Visibility into the present and future time-based impacts of DER, electrification, and demand response on the distribution system under alternate scenarios for customer adoption, customer behavior, weather, etc.
- Insight into the duration and frequency of equipment overloads to determine whether deterioration and emergent failure is likely to occur, reducing the risk of overload-caused customer outages. See the LVD Overload Risk Reduction section of the Reliability Roadmap for further discussion on this topic.
- Identification of system constraints and opportunities for system optimization at any hour of the year.

Several aspects of the Load Flow Tool Upgrade are required for the Company to maintain regulatory compliance now and in the future. First, the project will enable a comprehensive review of the fast track initial and supplemental review screens specified in R 460.946 and R 460.950 of the Michigan Interconnection and Distributed Generation Standards, and will

seek automation of the screens where technically feasible. It will also enable a Phase III advancement of the Company's hosting capacity maps as described in the Reliability Roadmap.

The Load Flow Tool Upgrade project is also required to complete the various distribution system impact analysis and data reporting requirements of the Michigan Transportation Electrification Plan, and will provide planning and interconnection engineers with the insights needed to successfully navigate the increased Distributed Generation program cap that was implemented by PA 235. Through the inclusion of CYME's Advanced Project Manager module, the project will provide cross-departmental visibility of distribution system enhancements being evaluated by LVD Circuit Planning, Substation Planning, System Protection, Metro Planning, Grid Automation and Distribution System Operations in a unified, as-planned network database. This integrated architecture will minimize the need for manual sharing of individual CYME studies between departments and will ensure that planned infrastructure upgrades are coordinated in a way that maximizes value delivered to customers.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the Load Flow Tool Upgrade investment category?

A. The Company is projecting Load Flow Tool capital expenditures of $3,333,000 in the bridge period, and $3,900,000 in the test year.

Q. How will the projected expenditures support the key objectives of the Reliability Roadmap?

A. The Load Flow Tool Upgrade project comprises foundational technology enhancements that will support many objectives of the Reliability Roadmap. Enabling time-series simulation capabilities in CYME will allow planners to evaluate the duration and frequency of potential device overloads to quantify whether deterioration, and eventual emergent failure, are likely to occur. See the *LVD Overload Risk Reduction* section of the Reliability Roadmap for further discussion on this topic. In addition to evaluating overloads, time-series power flows in planning tools will allow planners to proactively identify and mitigate voltage issues before they occur.

The industry standard forecasting tool introduced and integrated with CYME through the Load Flow Tool Upgrade will make planning for alternate future customer adoption, load growth, and weather scenarios a regular and defensible part of the annual planning process as discussed in the Reliability Roadmap.

In addition to the above, the Load Flow Tool Upgrade seeks to advance the accuracy, granularity, and frequency of updates to the Company's hosting capacity maps. The project will explore hosting capacity process automation using either EPRI DRIVE or CYME's Integrative Capacity Analysis module. For further discussion, see the Hosting Capacity Section in the Reliability Roadmap.

VIII. Operational Systems Modernization

Overview

Q. Please summarize the objectives of the Operational Systems Modernization Initiative.

A. Operational Systems Modernization is a Grid Automation initiative tasked with researching, developing, and demonstrating desired technologies to improve the Company's operational response for customers. The goals of the Operational Systems Modernization initiative are to:

- Leverage technologies to generate new operational capabilities;
- Enhance operational procedures to optimize the outage restoration process;
- Enable new grid functionality to meet future state business needs; and
- Consider interdependencies with other Grid Automation initiatives to support cross-functional use cases.

The Operational Systems Modernization initiative contains the implementation of a modern FLISR program and stakeholder engagement on DER Optimization.

Q. Please explain how the capital expenditures will be allocated across this investment category in the bridge period and the test year.

A. The Company is projecting capital expenditures in the bridge period and test year for each investment category as identified in Figure 10 below.

FIGURE 10
OPERATIONAL SYSTEMS MODERNIZATION CAPITAL EXPENDITURES ($000)

Operational Systems Modernization Investment Category	Bridge Period (Jan '25 - Mar '26)	Test Year (May '26 - Apr '27)
FLISR	2,300	2,900
Total	**2,300**	**2,900**

Fault Location Isolation and Service Restoration

Q. Please summarize the objectives of FLISR.

A. FLISR is an ADMS application that uses communicating grid equipment, such as line sensors and reclosers, to quickly detect and locate where faults are on the system, then automatically re-route power, isolating issues to minimize the number of customers impacted. FLISR will consist of three key components: software enablement within the ADMS, hardware deployment, and process updates. This project will include the integration of electric distribution system data as well as the testing and validation of the application solution capability. An important final piece of the implementation includes the creation and modification of operating procedures to ensure safe and efficient procedures are trained and used with co-workers.

Q. What work was completed in 2024 to support FLISR?

A. In 2024, the Company launched a stakeholder team to plan and prepare for the beginning of its 2025 FLISR implementation. The Company partnered with EPRI to develop a set of detailed design documents specifying all technical aspects of a FLISR solution. EPRI evaluated the Company's existing infrastructure, processes, and technology to create a specific roadmap leading toward the implementation of FLISR, as detailed in Exhibit A-153 (SAM-12). The Company communicated with other utilities currently using an operational FLISR application to understand and apply industry-proven best practices and methods.

Q. What work will be completed in 2025 to support FLISR?

A. Following the guidance of the EPRI roadmap, the Company in 2025 will begin needed software updates within its ADMS platform, begin the process of designing networks for the initial implementation, and develop standards throughout the organization to support

the deployment. The Company will continue developing its current FLISR product within ADMS to support the networks planned for installation. The further development of the application will enable the networks to automatically identify faults and provide solutions for available restoration opportunities. The FLISR algorithm will also be tested to ensure it accurately analyzes faults and avoids post-load transfer conditions that would result in overloaded equipment or customer voltage deviations. This testing is critical to ensure customers are not impacted by any anomalies that could arise from complex switching schemes. While the Company has the base software platform of FLISR in its ADMS, there are multiple applications within ADMS that the software is highly dependent upon. These necessary applications will need to be further developed and will require model maintenance to support a functional FLISR application. Distribution Power Flow ("DPF") and Spectra Insight, for example, are two applications within ADMS that perform iterative power flow calculations and perform violation processing respectively on the real-time model. Both applications will require hours of modeling and data validation, per feeder, to successfully support the FLISR application and evaluate the real time state of the distribution grid. The Company will be upgrading a portion of its ADMS platform to a new version to support improved functionality. To accompany the software, FLISR networks will be designed in 2025 using ATRs. ATRs, which the Company has installed throughout the state, will be used as the primary switching device in FLISR networks. The Company also plans to deploy new communication switching equipment on future FLISR networks to provide new capability for isolation opportunities, further limiting the impact of an outage to customers. This equipment is expected to include modern reclosers, as described

in the DCM section above, as well as new device types such as cutout-mounted reclosers and remote switches.

In 2025, the Company will evaluate the standards, processes, and procedures that will require updating due to the FLISR implementation. The work done in 2025 will pave the way for the further deployment of FLISR into 2026, and a longer-term rollout in subsequent years. In summary, the funding request in the bridge and test periods will allow the necessary updates to the DPF and SpectraInsight applications, update processes, procedures, and standards, and to install ATRs as the primary switching device thus establishing a network. Additional equipment such as cutout-mounted reclosers and remote switches will be evaluated to increase the number of opportunities to isolate an outage and limit the impact to customers.

Q. What capabilities and benefits do you expect FLISR to provide?

A. A FLISR system is designed to provide multiple critical capabilities including fault detection, fault location prediction, fault isolation, and service restoration. It does this by analyzing data from reclosers, line sensors, and other remotely communicating devices that are overlaid on an electronic map within ADMS. The FLISR application is controlled through ADMS's central logic. This centralized logic provides next generation switching automation through FLISR by analyzing the real time operating model and the telemetered devices that exist within it, to provide automatic switching solutions.

These switching solutions are analyzed through FLISR to avoid voltage deviations, to protect the distribution system from potentially hazardous post-load transfer configurations due to overloaded equipment, and to re-energize as many customers as possible. The Company also plans to upgrade chosen existing ATR loops that use

de-centralized control logic to the centralized FLISR architecture. The addition of centralized logic will enable the chosen de-centralized ATR loops to remain in automation year-round, mitigate loading limitations present on the loop during peak days, and increase switching capabilities. A successful implementation of FLISR on a de-centralized loop can then lead the way to upgrading the remaining de-centralized loops. An initial evaluation shows that upgrading the Company's eight most limited ATR loops from de-centralized logic to centralized logic that allows these extremely limited loops to remain in automation nearly year-round, avoids an estimated annual 330,000 CMI. This results in an estimated 1,713 customer outages avoided annually. FLISR also has the intelligence to determine what switching equipment can be opened and or closed to isolate an impacted area of the electric distribution system so that outages are constrained to a minimal portion of the system. These switching solutions can be performed remotely, reducing field switching time. A 2016 report by the DOE, titled *Distribution Automation: Results from the Smart Grid Investment Grant Program*, analyzed the benefits seen at various utilities after investing $7.9 billion in distribution automation technologies through a Smart Grid Investment Grant. The report states that per outage event, FLISR operations reduced the number of customers interrupted by 55% and reduced customer minutes of interruption by 53%.[4] The report elaborates that "Precise fault location enabled operators to dispatch repair crews accurately and notify customers of outage status, which reduced outage length and repair costs, reduced the burden on customers to report outages, and increased customer satisfaction."[5] As shown in Exhibit A-154 (SAM-13), the Company estimates that per FLISR network, 550,000 CMI will be avoided annually—this translates to an

[4] See footnote 1.
[5] See footnote 1.

estimated 2,750 customer outages avoided per year per network. As the Company expands into a statewide rollout, there will be many FLISR networks across the electric grid.

Another benefit of the program is its impact on safety. FLISR provides automatic isolation of faulted zones, which in turn decreases the safety risk of the public contacting energized downed wires. Since FLISR devices are telemetered, potentially downed wires can be automatically secured during blue sky days and storms. This saves field resources from traveling to the faulted location to manually secure downed wires and increases resource availability to focus on unsecured downed wires at non-telemetered locations. An increase in available field resources to attend unsecured downed wires results in greater relief support to non-utility employees guarding, such as public service officials. This directly supports MPSC Rule R 460.723 within the Service Quality and Reliability Standards for Electric Distribution Systems.

Q. How are FLISR networks selected and prioritized to maximize customer benefit?

A. FLISR networks will be selected based on historical reliability and potential for operability. Circuits with historically low reliability scores, specifically due to a high frequency of main line faults, will be prioritized to maximize benefit. In addition to selecting circuits based on low reliability, the Company will analyze options based on customer counts, sectionalizing capability, and the number of adjacent circuit tie devices. Neighboring circuits located in dense urban areas often provide a greater potential for load transfer capability and typically serve higher customer counts. Coupling this opportunity with a historically low reliability metric allows the Company to strategically select where to implement FLISR.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the FLISR investment category?

A. The Company is projecting FLISR capital expenditures of $2,300,000 in the bridge period, and $2,900,000 in the test year. It is important to note the requested investment in the bridge and test period is not for a full system-wide deployment, but only the initial implementation of this technology. Figure 11 provides additional details

FIGURE 11
ITEMIZED FLISR CAPITAL EXPENDITURES ($000)

FLISR Investment Category	Bridge Period (Jan '25 - Mar '26)	Test Year (May '26 - Apr '27)
Distribution Management System enhancements	$660	
Application Evaluations & Test Environment Simulations	$200	
Reclosers (11) for FLISR network	$612	$612
Network installation	$828	$2,288
Total	**$2,300**	**$2,900**

Q. How will the projected expenditures support the key objectives of the Reliability Roadmap?

A. The Company expects FLISR to be a flagship program that establishes a path to a more reliable electric distribution system. FLISR is poised to improve the management of electric outages by minimizing their impact and duration to customers. As described in the Reliability Roadmap, this project will automatically re-route power to limit the impact of outages. FLISR will both shorten outages through quicker fault detection and location, as well as eliminate outages by isolating issues to the smallest area possible.

DER Optimization

Q. Please summarize the objectives of the DER Optimization Initiative.

A. DER Optimization seeks to develop a standardized methodology for delivering important capabilities, including but not limited to the modeling, monitoring, operating, and coordinating needed to optimize and safely integrate DER into the electric distribution system. This approach includes research, planning, and development of hardware and software projects to evaluate DER management capabilities across the spectrum of DER types through the implementation of a DER Management System ("DERMS"). The Company defines DERMS as an enterprise scale software platform that is located at the utility's operational center. While broader applications such as edge DERMS and fleet DERMS are not explicitly included in this definition, it is important to note that they will be considered in the scope of the DER Optimization program.

Q. How is the Company planning to proceed with the DER Optimization initiative?

A. In Case No. U-21585, the Company agreed to form and lead a workgroup open to interested stakeholders from outside the utility to collect feedback that may influence the Company's future DER Optimization strategy and business case. The Company will also continue to actively participate in EPRI's DER Integration program and will explore additional opportunities to engage in DERMS-related working groups to both maintain and increase awareness of emerging best practices for DERMS implementations and valuing the benefits of DERs in other states. The Company intends to onboard a consultant to facilitate the workgroup and support the inclusion of key findings from all the above into a formalized business case that includes a comprehensive BCA and an analysis of Virtual Power Plants. This effort will inform investment requests in future cases.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the DER Optimization investment category?

A. The Company is not requesting funding in this case. Instead, the Company will work to establish a workgroup with the aim to bring stakeholders together to address the items raised in Case No. U-21585. The Company will continue to participate in the MPSC Staff workgroup on this topic.

Summary

Q. Please summarize how the investments in this category support the overall electric strategy and the Reliability Roadmap.

A. The FLISR program, once fully operational, will emerge as a cornerstone of the Company's overarching reliability strategy. FLISR is an industry proven approach for minimizing the impact and duration of outages on the electric distribution system. By bolstering the electric distribution system's capability for isolation, the FLISR program will substantially reduce the number of customers affected by outages. Additionally, added visibility through line sensors and other communicating devices will support reduced outage durations by gaining the ability to dispatch crews directly to the area of need.

As stated in the Reliability Roadmap, FLISR is a significant piece of the Grid Automation workplan.

IX. Weather Stations

Overview

Q. Please summarize the objectives of Company-owned Weather Stations.

A. In 2024, the Company hired an internal Meteorologist to conduct specific analysis on weather systems that impact the Company's grid. As noted in the Liberty Report Part II,

on page 94, there is a need to not only track weather conditions but to analyze historical trends that may adjust Consumers Energy's asset management strategy. The Company Meteorologist reviewed existing practices and concluded that there are large gaps of weather data throughout the service area due to the limited number of National Weather Service stations in Michigan. The data gathered from these additional weather stations will be used to:

- Inform storm preparation activities to speed up outage restoration by positioning resources;
- Analyze historical trends looking for a connection between various weather systems and the resiliency of the assets; and
- Feed data into the Company's outage prediction modeling to provide improved accuracy as supported by Company witness Andrew R. Snider.

Q. What type of data will be captured by these Weather Stations?

A. The Company has conducted a Request for Information across five weather station vendors. Key data to be collected includes temperature, wind speed, wind direction, barometric pressure, humidity, solar radiation, rainfall, fuel temperature, fuel moisture, and soil moisture. This data will be available for advanced analytics across many areas in the Company.

Q. How many weather stations are being proposed across the service territory?

A. The Company plans to install up to five weather stations as an initial implementation in this case, then add 25 weather stations in 2026, and an additional 70 weather stations in 2027. The total number of weather stations is expected to be 100 by 2027.

Q. Describe the analysis used to determine the total number of needed weather stations.

A. A 2018 report by EPRI[6], titled *Determining the Optimal Locations for Weather Sensors in a Mesonet*, stated the optimal-level grid network for the Company's type of topography is roughly 15 km (9.32 miles) in between sites. The Company has proposed installing weather stations 16 km (10 miles) in between sites, which is a slightly greater distance than the ideal grid network. That is equivalent to one weather station per 100 square miles. To complete the 10-mile by 10-mile grid resolution within the Company's more than 28,000 square mile service territory, Consumers Energy would need to install 100 Company-owned weather stations. This grid resolution includes the already installed National Weather Service weather stations. While the National Weather Service provides access to weather stations, large gaps remain around the state. The largest gaps in weather station data occur in Northeast Michigan. The average county land size in Northeast Michigan is 560 square miles, where the average county only has one to two weather stations monitoring wind. Worse yet, there are currently zero weather stations within the entirety of Gladwin County that monitor wind speed and wind direction.

Q. What benefits do you expect these Weather Stations to provide?

A. To prepare for severe weather, the Company employs the prestaging of line workers close to where the greatest impact is expected. These weather stations will provide real-time weather data signaling the most optimal placement of resources as a system is progressing across the state. Acting on this improved situational awareness enables faster restoration

[6] *Determining the Optimal Locations for Weather Sensors in a Mesonet*. EPRI, Palo Alto, CA: 2018. 3002007610. https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&cad=rja&uact=8&ved=2ahUKEwjQt82vyZSNAxWA4MkDHT-SOcgQFnoECCUQAQ&url=https%3A%2F%2Frestservice.epri.com%2Fpublicdownload%2F000000003002007610%2F0%2FProduct&usg=AOvVaw283Pq0-tgIqWG5IgGeYdyr&opi=89978449

times for customers. Reducing the duration of a storm not only helps the Company meet the MPSC Service Quality and Reliability Standards, but it can also avoid service restoration costs. As shown in Exhibit A-155 (SAM-14), the Company estimates avoided CMI of 12,575,250 from 2025 through 2036. Beyond the operational benefits, additional analytics will be performed to determine asset resilience and performance. The observed weather conditions will provide the Company insight to improve equipment, material, and engineering standards.

Increased weather data will also be used in the Company's developing AI outage prediction model as discussed by Company witness Snider. The more data the outage model has, the more accurate it can be. A study was published through EPRI, titled *Case Study: Demonstration of the Quantum Weather Storm-Prediction Model and Application,*[7] concluding that an increase in spatial and temporal resolution increased the accuracy of forecast models.

Q. What benchmarking was performed to support this investment?

A. Weather stations can provide valuable information around complex forecasting topography. Central Hudson Gas and Electric took part in the 2018 EPRI study, determining the optimal number of weather stations to maintain in their grid. Utilities across the United States have been able to increase their situational awareness for wildfire risk mitigation by installing weather stations across their electric grid. Portland General Electric ("PGE"), for example, has a network of more than 80 weather stations that provide detailed weather data, as well as AI-enhanced cameras that assist with fire detection and awareness. In addition, San Diego Gas and Electric ("SDG&E") currently has more than

[7] *Case Study: Demonstration of the Quantum Weather Storm-Prediction Model and Application.* EPRI, Palo Alto, CA: 2016. 3002004268.

220 weather stations within a 4,000 square mile service territory While wildfire detection is a growing space for many weather station vendors, the Company remains focused on improved outage response when storms impact customers.

Q. Please explain how the capital expenditures will be allocated across this investment category in the bridge period and test year.

A. The Company is projecting capital expenditures in the bridge period and test year for each investment category as identified in Figure 12 below.

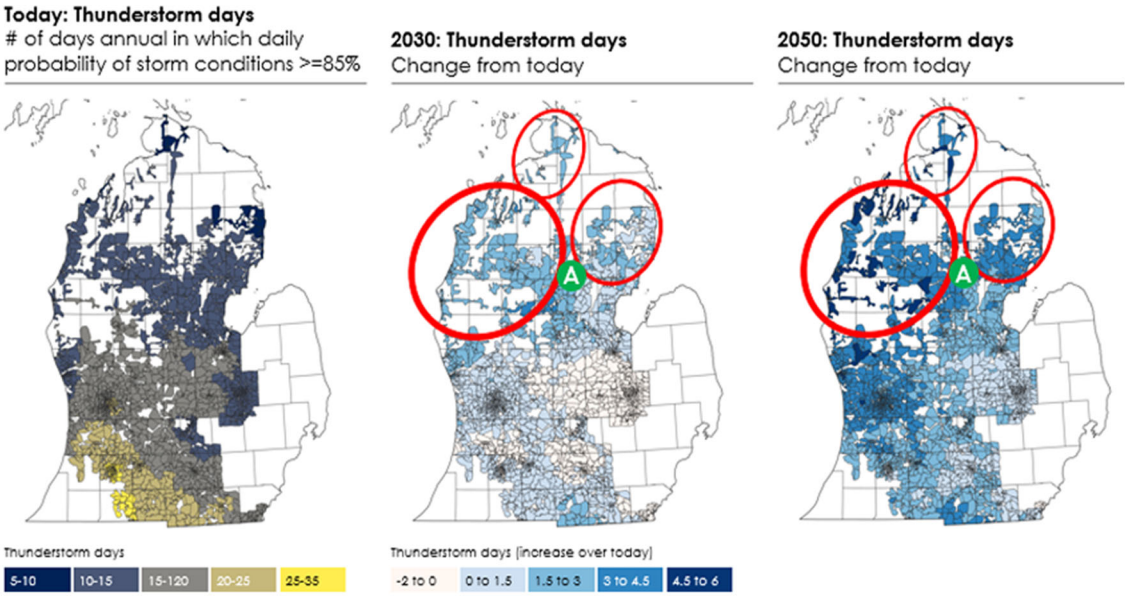
Figure 12
WEATHER STATIONS EXPENDITURE SUMMARY ($000)

	Bridge Period (Jan '25 - Apr '26)	**Test Year (May '26 - Apr '27)**
Weather Stations	71	362

Q. How will the projected expenditures support the key objectives of the Reliability Roadmap?

A.The decision to add weather stations to the electric grid was primarily made as a result of the Reliability Roadmap's identification of the risk of increasingly severe weather resulting from climate change. As seen in the Reliability Roadmap, the Company has experienced repeated instances of strong winds causing large-scale outages and a general increase in Major Event Days per year. The number of days with thunderstorms in the state of Michigan is anticipated to increase through 2050, as described in the Reliability Roadmap. See Figure 13 below.

FIGURE 13
2030 AND 2050 THUNDERSTORMS INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY

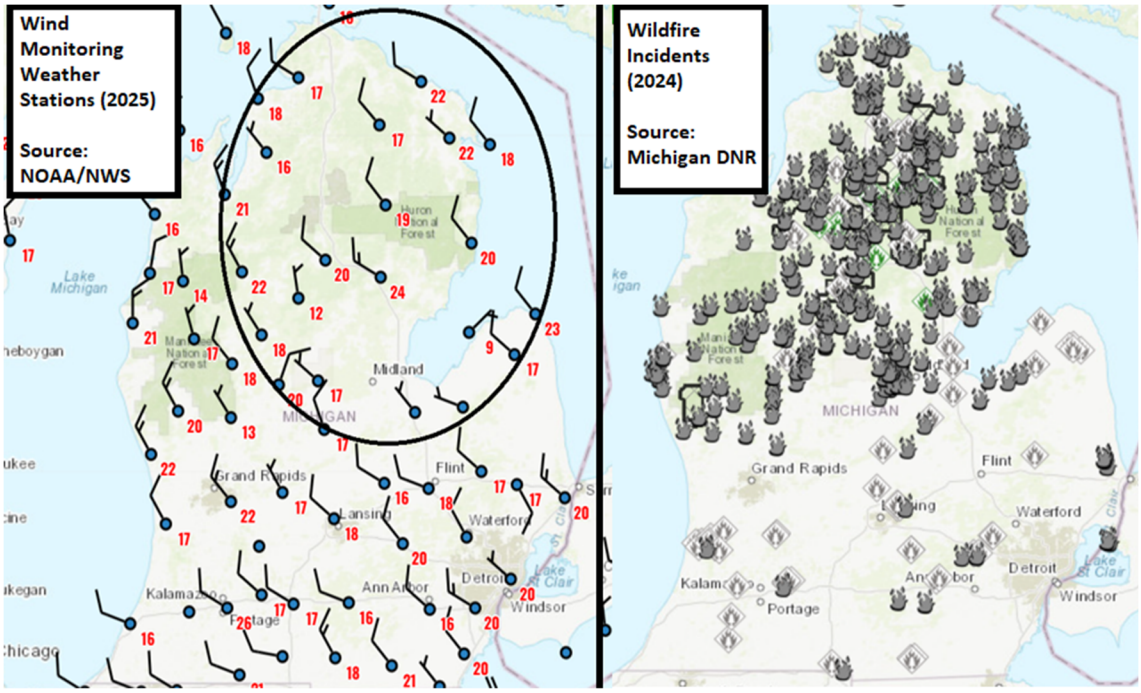


The greatest potential for an increase in thunderstorm days is in Northeast Michigan, where the least amount of weather data is available and where the fewest weather stations currently exist. Thunderstorms pose wind and lightning concerns, which correlate to potential outages and wildfire initiation risk.

Northeast Michigan additionally holds the highest wildfire risk zone within the Company's service territory. Figure 14 below compares the current National Weather Service wind monitoring weather stations with the wildfire incidents that occurred in 2024. Currently, the region with the highest wildfire risk in Michigan is correlated with the least amount of weather station data.

FIGURE 14

COMPARISON OF WIND MONITORING WEATHER STATIONS TO WILDFIRE INCIDENTS



There are currently 26 wind-monitoring National Weather Service weather stations in the Company's Northeast electric service territory, covering nearly 6,800 square miles. Based on the ideal 10-mile by 10-mile grid spacing between weather stations, Northeast Michigan should have at least 68 weather stations covering that region. The Company plans to install 44 of the proposed 100 weather stations in Northeast Michigan to increase situational awareness.

The Liberty Report Part II, pages 112-113, conclusion 6, determined more needs to be done to improve outage modeling. This additional weather data will be incorporated into the Company's modeling and used to make operational decisions that limit the impact of outages to customers.

Q. Please provide an example event when additional weather stations could have been beneficial to the Company and customers.

A. Michigan experienced a historic weather event in late March 2025, resulting in widespread accumulating ice in Northern Michigan and 14 confirmed tornadoes in Michigan. The ice accumulation in Northern Michigan was only comparable to an ice storm that occurred in February 1922, making it the worst ice storm to strike Northern Michigan in over 100 years. That storm led to the Governor declaring a state emergency for 10 counties in Northern Michigan.

Forecasting freezing rain and ice is one of the most challenging jobs for a meteorologist. Whether the precipitation lands on the surface as snow, rain, freezing rain, or sleet comes down to a few degrees in temperature. As previously mentioned, Northeast Michigan consists of the fewest weather stations in the state. The proposed weather stations could have provided the Company greater situational awareness around the exact type of precipitation that was accumulating based on the exact surface temperature.

The same storm system produced widespread damaging wind gusts and tornadoes in Southern Michigan. One of the already installed National Weather Service weather stations recorded a 96-mph wind gust in Jackson. That wind report provided a quick response to nearby crews to travel to Jackson before the outage was officially reported in the Company's system. Wind gusts are sporadic and inconsistent in nature. A wind gust report can vary greatly by a matter of miles. A greater number of operational weather stations within the Company's electric grid provides a greater opportunity for the Company to respond quickly to observed weather conditions.

X. Summary

Q. Please provide a summary of your testimony and the intent of investing in Grid Automation to support the Company's electric distribution system.

A. My testimony provided an overview of the Company's efforts to establish an automated and modernized electric grid. Grid Automation projects were shown to have provided benefits to customers through better reliability and cost control. The Company has a track record of proven successes as seen through the delivery of the ADMS, ATR Loop Schemes, CVR, and other programs that have become a normal part of running the business. Grid Automation investments have been shown to support the key objectives of the Reliability Roadmap and play a key role in building the grid of the future, as the Company installs new technology with proven capabilities on the electric distribution system.

Q. Please summarize the Grid Automation capital expenditure plan in this filing.

A. The Grid Automation capital expenditure plan outlined in this testimony is summarized in Figure 15 below, and as shown in Exhibit A-113 (MPK-3) line 14, columns (k) and (l). Dollars shown are in thousands.

Figure 15
GRID AUTOMATION EXPENDITURE SUMMARY ($000)

	Bridge Period (Jan '25 - Apr '26)	**Test Year (May '26 - Apr '27)**
Grid Automation	25,691	17,837

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

SCOTT A. MCPHAIL II

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Scott A. McPhail II, and my business address is 3201 E. Court, Flint, MI 48506.

Q. Are you the same Scott A. McPhail II who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Attorney General witness Sebastian Coppola regarding Line Sensors, Voltage Regulator Controllers, Peer-to-Peer Automation, Metro Modernization, and Distribution Asset Management. I will rebut the direct testimony of Association of Businesses Advocating Tariff Equity ("ABATE") witness Colin. T. Fitzhenry on Voltage Regulator Controllers; Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Jing Shi, P.E. on Distribution Asset Management; Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar (collectively the "Clean Energy Organizations" or "CEO") witness William D. Kenworthy and Great Lakes Renewable Energy Association ("GLREA") witness Richard Boehnke regarding Virtual Power Plants ("VPPs"); and Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan ("MNSC") witness Caroline Palmer on cost of service.

Q. How is your rebuttal testimony organized?

A. My testimony is organized by topic, addressing each witness within those topics.

Q. Are you sponsoring any exhibits?

A. No.

RESPONSE ON LINE SENSORS

Q. Please summarize Attorney General witness Coppola's proposed capital spending adjustments for Line Sensors stated on page 67, lines 1 through 15, of his direct testimony.

A. Attorney General witness Coppola conducted a unit cost analysis on the proposed investment in the bridge period. The 2024 unit cost of $3,637 was adjusted for inflation resulting in a unit cost of $3,741. This was multiplied by the 1,000 units forecasted to be installed resulting in capital expenditures of $3,741,000. Mr. Coppola then recommends that the difference between the requested amount of $6,116,000 and the calculated amount above, equaling $2,345,000, be removed from the bridge period. Mr. Coppola argues that the Company did not support the increase in expenditures in the bridge period.

Q. Do you agree with Mr. Coppola's recommendation to use a 2024 inflation adjusted unit cost to determine the bridge period investment for Line Sensors?

A. No. On page 19, lines 16 through 21, of my direct testimony, I explain that in addition to the cost of the line sensor itself, the AMPLE and RAMP software are necessary and included in the bridge period amount. These two software costs were itemized in my testimony on page 19, lines 20 through 21, at $3,100,000 and $2,083,000, respectively. In Case No. U-21585, the MPSC Order supported the funding of the RAMP software (page 111) and the Company has completed this work. For the AMPLE software, in my direct testimony on page 20, lines 3 through 7, it is explained that all line sensors cannot function without this software renewal. Like with RAMP, this software renewal has been

completed. The use of a 2024 unit cost is inappropriate because these software renewals occur on a three- to five-year cycle, and in 2024 there was no software renewal. Lastly, as stated on page 18, line 19, of my direct testimony, the Company has completed the mass deployment of these line sensors and secured the necessary AMPLE and RAMP software, and these bridge year dollars have already been spent.

RESPONSE ON VOLTAGE REGUALTOR CONTROLLERS

Q. Please summarize Attorney General witness Coppola's proposed capital spending adjustments for Voltage Regulator Controllers stated on page 67, lines 16, through page 68, line 18, of his direct testimony.

A. Mr. Coppola conducted a unit cost analysis on the proposed investment in the bridge period. The 2024 unit cost of $22,442 was adjusted for inflation resulting in a unit cost of $23,093. This was multiplied by the 294 units forecasted to be installed resulting in capital expenditures of $6,789,000. Mr. Coppola then recommends that the difference between the requested amount of $10,526,000 and the calculated amount above equaling $3,737,000 be removed from the bridge period. For the test year, the inflation adjusted unit cost of $23,647 was calculated from the unit cost described above, $23,093 multiplied by inflation of 2.4%. The test year number of units of 143 was multiplied by $23,647 equating to $2,382,000, which is $1,738,000 less than the amount requested in the test year. In summary, Mr. Coppola is requesting $3,737,000 be disallowed in the bridge period and $1,738,000 be disallowed in the test year, suggesting that there is a lack of explanation for the change in unit cost.

Q. Do you agree with Mr. Coppola's recommendation to use a 2024 inflation adjusted unit cost to determine the bridge and test year investments on Voltage Regulator Controllers?

A. No. As discussed at page 28, lines 8 through 21, of my direct testimony, a conventional unit cost is not appropriate for estimating these program costs. For example, there were several instances where materials to be used for a subsequent deployment year were purchased in the year prior to the deployment, or delayed into another year, thus giving an inaccurate view of unit costs when just comparing annual costs to the number of units. In addition, as shown in my testimony on page 27, Figure 7, the historical spending in 2024 was relatively lower compared to 2020 through 2022 spending. The reason 2023 and 2024 were lower was the result of the Company having leftover controls from the previous years, mainly 2022. This pull ahead purchase of materials helped offset the costs in subsequent years. These additional controls have now been deployed, and the Company needs to purchase the necessary materials in the bridge period and test year to complete the program.

Q. Please summarize ABATE witness Fitzhenry's disagreement with the Benefit Cost Analysis ("BCA") provided in Exhibit A-146 (SAM-5) for Voltage Regulator Controllers stated on pages 20 through 23 of his direct testimony.

A. Mr. Fitzhenry disagrees with the BCA, contending that it does not include costs such as taxes, Return on Equity ("ROE"), interest, and stranded costs, thus underestimating the total costs.

Q. What other concerns does ABATE witness Fitzhenry raise with the provided BCA in Exhibit A-146 (SAM-5)?

A. On page 23, lines 7 through 14 of his direct testimony, Mr. Fitzhenry states that most of the benefits are based on the assumption that line regulators installed prior to the year 2000 will all fail over the next 10 years and the Company has not provided any analysis to support that assumption. Mr. Fitzhenry removes the monetized benefits of $12,880,000 from the BCA which results in a net present value ("NPV") of $10,726,493 and is lower than the cash value of the project.

Q. What does Mr. Fitzhenry recommend for the Voltage Regulator Controller program?

A. As explained on page 23, lines 17 through 20, of his direct, Mr. Fitzhenry recommends that the pace should be slowed to 25% of the proposed installation rate. This results in upgrading 55 locations in 2025 and 54 locations in 2026. The reduction in capital expenses would be $7,894,500 in the bridge period and $3,840,000 in the test year corresponding to the 25% reduction in installation pace.

Q. Do you agree with the assessment of Mr. Fitzhenry that the BCA at Exhibit A-146 (SAM-5) understates all the costs of the Voltage Regulator Controllers?

A. In part, yes. Mr. Fitzhenry is correct to state that a utility has other costs beyond the initial purchase and installation price such as taxes, ROE, and while no standard has been established on what should be included in the BCA when evaluating electric distribution investments, in this case, the Company offered a BCA estimate of the value of this replacement program. Mr. Fitzhenry suggests that the project would likely be less cost-effective if these additional costs were included. However, it is also important to remember that investment decisions on the electric grid are not solely based on a

cost-effectiveness test. On pages 23 through 25 of my direct testimony, I explain the other benefits customers see from this program, including improved power quality, as required by MPSC R 460.3702 (Rule 702); reduction of customer minute interruption ("CMI"), included in Exhibit A-146 (SAM-5) at 56,625 minutes; and reduced electrical and traffic exposure for Company electric line workers through the use of remote monitoring. A holistic evaluation of all the benefits should be considered.

Q. Please describe the Company's assumptions in the BCA regarding the average life of a controller.

A. Since the start of this project, the Company collected field data to better understand how these devices perform. Field data from over 3,000 regulators were analyzed and found that only five were manufactured in 1988 or earlier. This demonstrates that the typical operational lifespan of these regulators does not exceed 37 years. Furthermore, around 60% of the regulators that failed during the project were identified to be manufactured before the year 2000. This reinforces our confidence that the majority of field regulators, if not addressed by the Line Regulator Project, would fail between 2027 and 2037 as they approach their maximum lifespan. The BCA reflects that the average life of a control is 20–25 years, and it reasonably assumes that failures are more likely in the 10 years following that period. The Company's empirical field data supports this assumption. These failures lead to poor power quality, which negatively affects customers and risks non-compliance with MPSC R 460.3702 (Rule 702). Because of this project, those future adverse impacts are avoided.

Q. Do you agree with Mr. Fitzhenry's recommendation to slow the Voltage Regulator Controller program to 25% of its current rate of deployment?

A. No. It is unclear how Mr. Fitzhenry arrived at 25%. Slowing the installation rate will jeopardize the competitive contract described in my direct testimony on page 27, line 13, through page 28, line 4. The Company has dedicated Construction Labor to efficiently complete this project. The savings described on page 28, line 3, of my direct testimony amounting to $1.5 million has been built into this project and slowing the pace will erode the economies of scale that customers are benefiting from through a lower construction cost.

Q. What recommendation do you have related to voltage regulator controllers?

A. The voltage regulator controller replacement program has been underway since 2020 and has received support in all prior rate cases. The Company is nearing completion of this defined program, expected in 2026, within the test year. The Company has already made investments this year in 2025, purchasing the materials for the work to complete this year and in the bridge period 2026. Given the benefits described in my direct testimony and my explanations explained above, the amount requested in my direct testimony should be approved.

RESPONSE ON DISTRIBUTION ASSET MANAGEMENT

Q. Please summarize Attorney General witness Coppola's proposed capital spending adjustments for Distribution Asset Management ("DistAM") stated on page 72, lines 5 through 7, of his direct testimony.

A. Mr. Coppola recommends the removal of capital expenditures in the amounts of $1,740,000 for the bridge period and $4,050,000 in the test year.

Q. What are Mr. Coppola's concerns with the DistAM initiative?

A. Mr. Coppola argues that the BCA at Exhibit A-152 (SAM-11) is outdated and that current overall spending (beyond this rate case) is projected at $21 million since inception of the initiative. Mr. Coppola also takes issue with the benefits listed in the BCA, stating that they are vague concepts and would not provide realistic cost savings. Mr. Coppola goes on to state that the Asset Repository ("AR") cost is projected at $8.8 million, increased from the original estimate of $2.5 million, and argues that this indicates more upfront research should have been performed prior to proceeding with this initiative. Mr. Coppola contends that the BCA is now stale, and the higher projected costs make the NPV no longer favorable. Additionally, he argues that it would be premature to include the Asset Performance Management ("APM") costs in the rate case because the project is in the "planning phase."

Q. Please summarize Staff witness Shi's proposed capital adjustments and concerns with the DistAM initiative.

A. Staff witness Shi recommends a disallowance of $770,000 in the bridge period and $2,640,000 in the test year, contending that the Company did not explain why funds have not been spent on APM and how the projected funds in this current case will be used.

Q. Summarize Commission orders related to the DistAM Initiative.

A. The Commission originally approved the DistAM project in Case No. U-20697 and re-approved in the December 22, 2021 Order in Case No. U-20963. The concept approval at that time projected $12 million for the project. In Case No. U-21585, the Commission stated as follows in its March 21, 2025 Order, page 110: "The Commission finds that Consumers has not provided adequate data supporting recovery of the increased costs of

the DistAM program." Based on this Order, my direct testimony in this case provided additional justification along with a BCA in Exhibit A-152 (SAM-11) that shows future year expenses. As explained on page 51, lines 16 through 17, of my direct testimony, the total projected spend through the test year in this case is $13.6 million, which is only $1.6 million more than the previously approved amount of $12 million.

Q. Do you agree with Mr. Coppola's concerns and removal of the capital expenditure for the DistAM initiative?

A. No. The requested amounts in the bridge period and test year are necessary to continue the development and deployment of this initiative. The DistAM initiative works best as a whole, explained on page 49, line 19, through page 50, line 2, of my direct testimony. Each of the three primary components (AR, APM, Asset Investment Planning ("AIP")) all build on each other to improve capital efficiency. While the project costs are forecasted to increase since the initial concept approval, the Company continues to update and annually refine its estimate as more is learned. Page 52 of my direct testimony offers an explanation as to why this occurred. The Company continues to evolve based on new information, including avoiding $3.3 million in capital and $1 million in operating and maintenance ("O&M") expense based on building an internal APM solution instead of a vendor provided solution. The avoided $1 million per year in O&M expense was not included in the BCA, further supporting the investment. Lastly, it is incorrect to exclude the APM funding because it is in a planning phase. The APM is scalable, meaning as each health score is developed for each asset, that information becomes useful and will be used to guide investment decisions. The entire APM does not need to be complete for all in scope assets to begin to extract value out of it. Funding is being requested through April 2027, providing

a year after the end of the planning phase to add in assets and leverage their health scores as each asset is brought in.

Q. Do you agree with Staff witness Shi's reasoning to disallow capital investment on the APM portion of the DistAM initiative?

A. No. Staff witness Shi accurately described the purpose of the DistAM initiative and correctly summarizes the three key workstreams that make up the initiative as a whole. See pages 5 through 7 of Staff witness Shi's direct testimony. Each of the three workstreams (AR, APM, AIP) complement each other, providing greater value when used collectively. The APM is highly dependent upon the AR because the source data needed to calculate the asset health score will come from the AR. Funds have not yet been spent on the APM because the Company shifted focus to add more assets into the AR versus further development of the APM. The resources being used to build the AR are skilled in database structure and data design. To leverage this unique skillset, it was more efficient to streamline this workload and keep these resources focused on adding assets into the AR. While there has not been spending on the APM, it is more appropriate to consider DistAM as a whole given the interdependencies between the three workstreams. Given that perspective, the Company has invested and made progress on the overall DistAM program with the AIP complete and on track to have seven electric assets in the AR by the end of 2025.

Q. Considering the testimony of the Attorney General and Staff, what recommendation do you have related to DistAM?

A. The Commission should approve the Company's requested DistAM funding in this case. Pursuant to the Commission's order in Case No. U-21585, the Company has provided

updated data, including total costs, in this case. The Company intends to follow through on the recommendation provided on page 87 of the Liberty Consulting Group ("Liberty") report Part II by completing the holistic DistAM initiative including the AR and APM components discussed in this case. Lastly, in the Commission's July 10, 2025 Order in Case No. U-20147, in Exhibit A Section III, Part A, it is required for the Company to provide in its Distribution System Plan ("DSP") a data-based review on the general health and condition on its distribution system assets. This is precisely what the APM and the overall DistAM program aims to deliver. Failure to approve this investment risks the level of detail the Company will be able to provide in compliance with this order.

RESPONSE ON PEER-TO-PEER AUTOMATION AND METRO MODERNIZATION

Q. Please summarize Attorney General witness Coppola's proposed capital spending adjustments on Peer-to-Peer Automation and Metro Modernization.

A. At page 69 of his direct testimony, Mr. Coppola recommends the removal of capital expenditures for the combined Peer-to-Peer Automation and Metro Modernization initiatives in the amounts of $1,200,000 for the bridge period and $920,000 in the test year, arguing that there is a lack of support for these projects.

Q. Do you agree with Mr. Coppola's recommendation related to the Peer-to-Peer Automation investment?

A. While the Company does not agree with Mr. Coppola's reasons for removing these expenditures, the Company agrees to withdraw this projected investment of $895,000 in the bridge period and $270,000 in the test year for Peer-to-Peer Automation. The Company intends in a future case to seek funding for this project.

Q. Do you agree with Mr. Coppola's recommendation related to the Metro Modernization investment?

A. No. Exhibit A-151 (SAM-10) details the reliability benefits for customers of the Metro Modernization project using an avoided CMI calculation. Additionally, Exhibit A-151 (SAM-10) and my direct testimony at page 41, lines 5 through 7, provide an estimate on the safety benefit listed as a reduction of 185 hours of exposure in a confined space. The Metro Modernization project has two primary purposes: (1) improve reliability through remote operations and (2) improve safety for the public and the Company's electric line workers. This was described in my testimony on page 42, lines 10 through 20. While safety incidents in underground Metro electrical systems are rare, they can be extremely dangerous if they do happen[1]. The sensing and switching technology the Company plans to deploy is not new technology or experimental in the industry; the technology is only new to the Company. The direction of this project, like many of the projects within the Grid Automation department, is to engineer how these proven technologies will be used on the Company's system to benefit customers.

Q. Please describe ABATE witness Fitzhenry's discussion of the Metro Modernization project.

A. At page 27, footnote 44 of his direct testimony, Mr. Fitzhenry suggests that the proposed investments appear to be for research stating only a reduction in customer outages was considered.

[1] Boston Manhole Explosions Injure 1, Force Evacuations – NBC Boston - https://www.nbcboston.com/news/local/multiple-manhole-fires-reported-in-boston/2737181/

Q. Do you agree with Mr. Fitzhenry's characterization of the Metro Modernization project?

A. No. On page 41, lines 11 through 16, of my direct testimony, I describe the sites to be chosen and the specific use cases that will drive the benefits outlined. This includes environmental sensor detection and upgraded switching devices with Supervisory Control and Data Acquisition ("SCADA") capabilities for remote operations.

RESPONSE ON VPPs AND DISTRIBUTED ENERGY RESOURCES

Q. Please summarize CEO witness Kenworthy's recommendations to the Commission regarding the Distributed Energy Resource ("DER") Management System ("DERMS") Workgroup.

A. On page 4, lines 10 through 29, of his direct testimony, Mr. Kenworthy references the Commission's directive to the Company regarding DERMS in Case No. U-21585.

On page 5 of his direct testimony, Mr. Kenworthy states his understanding that the MPSC's Order in Case No. U-21585 requires that "the stakeholder-led DER optimization business case will evaluate VPP potential alongside DERMS capabilities." Mr. Kenworthy then acknowledges that the Company is not seeking DERMS funding in this case, yet recommends that the Commission order the Company to convene the workgroup.

In parallel with this recommendation to convene the workgroup, Mr. Kenworthy recommends in part, on page 17 of his direct testimony, that the Commission should require a VPP filing within six months that includes program tariffs, aggregator contracts, enrollment channels, capacity targets, and measurement and verification.

Q. Do you agree that a workgroup should be convened?

A. Yes. The Company agrees that a DERMS workgroup will be helpful in the development of a BCA, but that the development of a BCA would be premature at this time given the ongoing efforts to standardize a format to be used to evaluate these types of investment as part of Case No. U-20898. Based on Mr. Kenworthy's definition of VPPs on page 9, lines 6 through 11 of his direct testimony, the efforts underway within the Benefit-Cost Analysis Tool Collaborative apply (e.g. Demand Response, Distributed Generation, Electric Vehicles). Furthermore, in Case No. U-21585, the Commission asked the Company to conduct a workgroup and associated BCA prior to a request for cost recovery for DERMS, and the Company is not seeking cost recovery at this time.

Q. Do you agree with CEO witness Kenworthy's and GLREA witness Boehnke's definitions of VPPs?

A. The Company generally agrees with the conceptual definitions of VPPs provided by Mr. Boehnke and Mr. Kenworthy, but is unclear if VPPs in their present state of development are capable of delivering the full stack of benefits included in the definition. Mr. Boehnke cites the U.S. Department of Energy's ("DOE") definition (page 10, line 18, through page 11, line 2, of his direct testimony):

> VPPs are aggregations of distributed energy resources (DERs) such as rooftop solar with behind-the-meter batteries, electric vehicles (EVs) and chargers, electric water heaters, smart buildings and their controls, and flexible commercial and industrial loads that can balance electricity demand and supply and provide utility-scale and utility-grade grid services like a traditional power plant. VPPs enroll DER owners—including residential, commercial, and industrial electricity consumers—in a variety of participation models that offer rewards for contributing to efficient grid operations.

He also states on page 3, lines 5 through 10, of his direct testimony that VPPs are a "mature, essential, and cost-effective grid resource," and that they are "capable of providing utility-scale, utility-grade services, delivering affordable, reliable, and resilient power to ratepayers." The Company believes that these statements are premature and require demonstrated testing to determine these claims.

Mr. Kenworthy offers a similar definition for VPPs on page 9, lines 6 through 11, of his direct testimony:

> A Virtual Power Plant (VPP) is an aggregation of distributed energy resources—such as smart thermostats and water heaters, residential batteries paired with rooftop solar, EV managed charging, and flexible C&I loads—coordinated to balance supply and demand and deliver utility-grade grid services. It organizes customer flexibility into dispatchable capacity that reduces peaks, defers distribution infrastructure investment, and lowers system costs.

While these definitions align with common aspirations for VPPs and the benefits they may provide, questions remain as to how a VPP functions to provide "utility-scale and utility grade services." Without full integration of VPPs into utility operational systems and recovery for a utility owned and operated DERMS, it is not clear that VPPs are capable of delivering value streams outside of reducing system-level peak demand, and could potentially put the grid at risk if the VPP does not respond to dispatch signals that are mandatory to meet grid needs.

The DOE Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update report introduced in both Mr. Kenworthy's and Mr. Boehnke's direct testimony discusses this limitation in the key take-aways on page 23, as well as in the footnotes on page 29 and

30.[2] This point is also emphasized on page 55[3] of the Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment Report that the DOE references on pg. 21 and 64.

Mr. Kenworthy appears to acknowledge limitations of VPPs absent integration into utility operational systems such as DERMS/ADMS,[4] but Mr. Boehnke does not. While page 48, Figure 13 of Mr. Boehnke's direct testimony acknowledges the potential need for a DERMS in the Program Operator Role, Mr. Boehnke also states at page 49 of his direct testimony that "[e]ach of these primary roles can be operated by the utility, however, they need not be. Rather, it is critical to create a Market where the resources aggregated in VPPs can be bought and sold."[5] The Company disagrees with any position that seeks to minimize the operational needs of the Company that allow the Company to deliver safe and reliable power to all Consumers Energy customers in Michigan. As these operations become mission critical, such as in the case of a needed infrastructure upgrade deferral, the Company's grid operators must have the ability to monitor whether the VPP responds to third-party or utility dispatch signals and take appropriate actions based on grid needs if they do not.

Q. Do you agree that VPPs are ready for immediate implementation outside of a pilot process?

A. No. Mandating VPP implementation in their present state outside of a pilot raises utility operations concerns, particularly in the absence of established technical standards.

[2] Department of Energy, January 2025,"Pathways to Commercial Liftoff: VPPs 2025 Update" Accessed at https://virtual-peaker.com/wp-content/uploads/2025/09/2025-Jan-LIFTOFF_DOE_VirtualPowerPlantsUpdate.pdf
[3] "Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment" Accessed at https://emp.lbl.gov/publications/distributed-energy-utility-scale-30
[4] Direct Testimony of William D. Kenworthy: page 6, lines 1-2; page 10, lines 19-22; page 12, lines 1-7; page 17, lines 7-11.
[5] Direct Testimony of Richard Boehnke, page 49, lines 5-7.

Both Mr. Boehnke and Mr. Kenworthy suggest that VPPs are ready for immediate deployment, and that they've reached a maturity level that does not require pilots. On page 10, lines 2 through 4, of his direct testimony, Mr. Boehnke states that "A new pilot program will be insufficient to show the potential of VPPs and too limited to deliver the grid services and capacity as required to accommodate rapid load growth." He also states on page 3, lines 11 through 13, of his direct testimony that "VPPs are low-cost solutions, costing significantly less per kW-year than conventional resources, and that they can be deployed rapidly to address immediate challenges." Mr. Kenworthy states on page 5, line 19, through page 6, line 2, of his direct testimony that he does not believe a pilot is necessary.

The DOE's "Pathways To Commercial Liftoff: Virtual Power Plants 2025 Update" report that both Mr. Boehnke and Mr. Kenworthy reference highlights the present lack of standardization for VPPs and the complexities and limitations that result on page 23. On page 24 of the DOE report it states that "In the past year, DOE and other industry actors have launched or expanded efforts to standardize critical areas of VPP operations to reduce complexity and cost of implementation and increase reliability of performance." Page 24 through 27 of the report discuss eight critical VPP standardization initiatives that are taking place across the industry.[6]

It is important to note that based on the DOE's "Pathways To Commercial Liftoff: Virtual Power Plants 2025 Update" report, page 24, Section 3 part ii, very few of these initiatives are complete, and many have commenced within the last year or are yet to commence. The Company is particularly interested in participating in EPRI's FlexIT

[6] Department of Energy, January 2025,"Pathways to Commercial Liftoff: VPPs 2025 Update" Accessed at https://virtual-peaker.com/wp-content/uploads/2025/09/2025-Jan-LIFTOFF_DOE_VirtualPowerPlantsUpdate.pdf

initiative, that was announced in May 2025. Among other benefits, the initiative seeks to establish standards for the core utility-to-VPP/aggregator interactions.[7]

The Company is not aware of interoperability or integration standards governing VPPs. As a result, each third-party aggregator develops and operates proprietary platforms that require custom integration into utility operational systems. This creates a fragmented and inefficient landscape, where utilities must manage multiple tailored interfaces, data formats, and communication protocols. Such complexity increases the risk of operational inconsistencies, cybersecurity vulnerabilities, and higher implementation and maintenance costs in the long-term. These concerns put at risk the ability to safely and effectively incorporate VPPs/third-party aggregators at scale into core grid operations.

Currently, mandating widespread implementation of VPPs outside of an established pilot process poses unnecessary risks to system integrity, operational efficiency, and customer reliability. The Commission has already ordered that the Company is required to analyze the use of VPPs as part of developing a business case for DERMS prior to the Company requesting recovery for a DERMS in a future electric rate case. It would be premature to impose any additional requirements related to VPPs at this time.

RESPONSE ON COST OF SERVICE REGARDING BI-DIRECTION POWER FLOW

Q. On page 15 of her direct testimony, MNSC witness Palmer states that "One-way power flow is no longer the reality. Today, the power system is changing such that DERs are making bidirectional power flow more common on the distribution system, in turn providing generation and other services to higher voltage customers who

[7] EPRI FLEXIT: https://epri.co/flexit

previously only benefitted from centralized generation delivered at the transmission or primary level." What is your response?

A. The extent of bidirectional power flow occurring between the low voltage distribution ("LVD") and high voltage distribution ("HVD") system is de minimis. The distribution substation load data provided in the Company's response to discovery request U-21870-MNSC-CE-0207 reveals that only 0.39% of total MWh flowed in the reverse direction between LVD Primary (e.g. Voltage 3) and the HVD (46 kV and 138 kV) system.

While the Company is able to track the occurrence of bidirectional flow at certain substations using Distribution SCADA data, as explained in discovery response U-21870-MNSC-CE-0222 (Exhibit MEC-17), the Company does not currently have the capability to produce comprehensive datasets that capture the full extent of bidirectional flows across the entire distribution system. This limitation is especially pronounced between the LVD secondary (Voltage Level 4) and LVD primary (Voltage Level 3) systems, where downstream customer density is high and devices capable of sensing reverse flow to the LVD primary system are few. Advanced Metering Infrastructure ("AMI") can inform when DER interconnections are exporting to the LVD secondary system, but cannot provide visibility of where exports flow beyond the point of interconnect.

Q. Does this conclude your rebuttal testimony?

A. Yes.

THE COURT: Next is company witness Ashley E. Meschke, who had direct testimony consisting of a cover page and 13 pages of questions and answers and Ms. Meschke sponsored exhibits A-156 through A-159.

THE COURT: Are there any objection to the admission of this testimony or these exhibits?

Hearing none. The direct testimony of Ashley Meschke is bound in the record and Exhibits A-156 through A-159 are admitted.

(At 3:01 p.m., Exhibits A-156 through A-159 admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

ASHLEY E. MESCHKE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Ashley Meschke, and my work address is One Energy Plaza, Jackson, MI 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Lean Strategy.

Q. Please review your educational and business experience.

A. I hold a bachelor's degree in Criminal Justice with a specialization in Security Management from Michigan State University, and a master's in Infrastructure Planning and Management from The University of Washington. I joined Consumers Energy in 2012, and for the last eight years of my career I have worked with different areas of the Company to improve metrics using lean methodologies including gas, electric, and customer. For the last six years, I have been accountable for leading teams dedicated to driving performance improvement and achieving targets associated with the Employee Incentive Compensation Plan ("EICP") operational goals.

Q. What are your responsibilities as Director of Lean Strategy?

A. In the Director of Lean Strategy role, I am responsible for the development, governance, and administration of the EICP operational goals. This includes but is not limited to the development of annual goals and associated targets, facilitating the development of plans to support goal achievement, ensuring the Company's lean operating system is leveraged to manage performance at various levels of the organization, and ensuring internal reporting standards are met.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have testified in Case Number U-21806, the Company's Gas Rate Case currently pending before the Commission.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose is to provide support for Consumers Energy's request for rate recovery for the test year employee compensation costs related to the EICP operational goals. Specifically, I will outline the operational goals included in Consumers Energy's EICP and how they provide customer-related benefits.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-156 (AEM-1)	2024-2025 EICP Operational Goals;
Exhibit A-157 (AEM-2)	2024 Customer Benefits: Employee Safety;
Exhibit A-158 (AEM-3)	2024 Customer Benefits: Reliability; and
Exhibit A-159 (AEM-4)	2024 Customer Benefits: Culture Index – Reduced Employee Turnover.

Q. Please explain the process for establishing the Company's EICP goals.

A. Each year, the Company identifies key operational and financial goals to focus on for the next year. The EICP operational goals are established by analyzing progress on the Company's strategic initiatives and developing key performance indicators that focus on driving performance improvement. The Company establishes operational goals grounded in delivering customer value through safe, reliable, affordable, clean energy service across the business. Operational goals are intended to be cross-functional and apply to all eligible employees to incentivize goal achievement through daily continuous improvement and

application of our Lean operating system, The CE Way. Operational goals are developed in partnership with the Company's leadership team and are approved annually by the Board of Directors. The process for developing annual targets is outlined later in my testimony.

Q. What operational goals will make up the 2025 EICP portfolio?

A. The EICP operational goals for 2025 include Employee Safety, Culture Index, Customer Experience Index, Electric Reliability, Waste Elimination, and Methane Emission Reduction. As outlined in Company witness Amy M. Conrad's testimony, the Company is not seeking recovery for Waste Elimination due to the financial nature of the operational goal. As outlined in Exhibit A-71 (AMC-1), operational goals have not changed from the 2024 to 2025 plan year; however, targets have changed to drive continuous improvement.

Q. Please explain the Employee Safety goal.

A. The Employee Safety goal is composed of three components: (1) Recordable Incident Rate (2) High Risk Injuries (3) Fatalities. The Recordable Incident Rate accounts for 30% of the metric and is measured using the Occupational Safety and Health Administration ("OSHA") industry standard. High-Risk Injuries account for 70% of the metric and include both OSHA recordable and non-recordable incidents with the potential for resulting in a severe injury or fatality. The Edison Electric Institute's ("EEI") Safety Classification Learning Model is leveraged as the industry standard for reporting and High-Energy Serious Injury or Fatality ("HSIF") and Potential Serious Injury or Fatality ("PSIF") are included. If there is a fatality, there is a 0% payout for the Employee Safety operational goal in its entirety. Please refer to A-157 (AEM-2) for additional information on the calculation method.

Q. Why is the Employee Safety goal included in the EICP?

A. Employee Safety is foundational to the success of the Company. Creating and maintaining a safe workplace and culture shows the Company's commitment to its coworker's wellbeing and their ability to go home safely every day.

When employees work safely it translates to delivering safe, reliable, affordable, and clean energy services to customers—while completing the work more efficiently, and avoiding costs associated with injuries. Customer benefits associated with Employee Safety are outlined later in my testimony.

Q. Please explain the Culture Index goal.

A. The Company uses an all-employee survey to determine the Culture Index, which is made up of three indices: (1) Engagement; (2) Empowerment; and (3) Diversity, Equity, and Inclusion. The indices are measured leveraging industry standards established by Korn Ferry, and data is collected leveraging the Qualtrics survey platform. Each of the three indices are derived by averaging the favorability score from employee responses. Additional information on the calculation method is outlined in Exhibit A-156 (AEM-1).

Q. Why is the Culture Index goal included in the EICP?

A. The Culture Index goal aims to enhance employee experience and engagement. Gallup's meta-analysis shows that companies with high employee engagement have 10% higher customer loyalty and engagement, 14% higher productivity, 43% less turnover, and 18% less absenteeism compared to those with low engagement[1]. Benchmark data indicates that peer utilities have a turnover rate of 7.3%, while the Company's four-year historical average is 2.4%. Gallup estimates turnover costs at 1.5-2.0 times the employee's salary. By

[1] https://www.gallup.com/workplace/285674/improve-employee-engagement-workplace.aspx%23ite-285704

maintaining a 2% competitive advantage over peers and using a 1.5 multiplier as the conservative end of Gallup's estimate, the Company avoids at least $7,064,260 in annual turnover costs. Exhibit A-159 (AEM-4) shows the calculation in further detail.

Q. Please explain the Customer Experience Index goal.

A. The Customer Experience Index is an industry standard developed and administered by Forrester[2] to measure the quality of customer service based on three questions: Did we meet your needs? Was it easy to do business with us? Was the experience enjoyable? The metric focuses on the following experiences: (1) Billing and Payment, (2) Outage, (3) Moving, (4) Field, and (5) Other across the following channels: (1) Digital (website and mobile application), (2) Live agent, and (3) the Interactive Voice Response ("IVR"). Please refer to A-156 (AEM-1) for additional information on the calculation method.

Q. Why is the Customer Experience Index goal included in EICP?

A. The Customer Experience Index goal focuses on ensuring when customers contact Consumers Energy, customer needs are met, the interaction is easy for the customer, and the experience is enjoyable for the customer. This results in enhanced productivity (e.g., reducing the number and duration of customer calls, which benefits the Company and the customer) and customer value (e.g., quick, easy, and enjoyable solutions for customer experiences).

Q. Please explain the Electric Reliability goal.

A. The Electric Reliability goal is measured using the System Average Interruption Duration Index ("SAIDI") as the industry standard to measure and improve performance. SAIDI has two components for measuring and reporting reliability as follows:

[2] https://www.forrester.com/research/

(1) The System Average Interruption Frequency Index ("SAIFI") – this indicates the frequency of outages that occur due to system condition, configuration, and related external conditions (e.g. weather patterns, forecasts, etc.)

(2) The Customer Average Interruption Duration Index ("CAIDI") – this indicates how long interruptions last due to system conditions, resources available, number of interruptions, and storm restoration activities.

SAIDI results are calculated by multiplying SAIFI and CAIDI. SAIDI is calculated excluding Major Event Days ("MEDs") to normalize performance data for unusually severe weather.

Q. Why is the Electric Reliability goal included in EICP?

A. Benchmarking and internal data indicate that reliability is one of the top drivers for overall customer satisfaction, and the Company is committed to providing safe, reliable, and affordable electric service. The Electric Reliability goal is directly aligned with the Company's Electric Reliability Roadmap[3] (i.e., Electric Distribution Infrastructure Investment Plan) and will position the Company for future success as electric demand increases. Improving electric reliability also provides an economic benefit to customers and is discussed later in my testimony.

Q. Please explain the Methane Emissions Reduction goal.

A. The Methane Emissions Reduction goal aims to reduce fugitive methane emissions associated with the Company's natural gas system.

Reductions are achieved through the following work activities:

(1) Retiring and replacing miles of natural gas distribution mains;

[3] https://www.consumersenergy.com/-/media/CE/Documents/company/electric-generation/ediip-report.pdf

(2) Retiring and replacing natural gas distribution services (both vintage and non-vintage materials);

(3) Completing natural gas distribution system leak replacements;

(4) Performing well plug and abandonment activities; and

(5) reducing compression venting.

Reductions are measured in metric tons, leveraging the emission factors outlined in the Environmental Protection Agency's Greenhouse Gas Reporting Rule, 40 CFR Part 98 Subpart W.

Q. Why is the Methane Emission Reduction goal included in EICP?

A. In 2020, Michigan's Governor signed an executive order creating the Michigan Healthy Climate Plan, which outlines goals for Michigan to achieve economy-wide carbon neutrality no later than 2050, and to maintain net negative greenhouse gas emissions thereafter. The executive order aims for a 28% reduction below 2005 levels of greenhouse gas emissions by 2025[4]. The federal government has established goals to reduce greenhouse gas emissions by 50-52% by 2030 and achieve net-zero emissions by 2050[5]. The EICP Methane Emissions goal is directly in support of state and federal goals and aligns with the Company's Natural Gas Delivery Plan that is founded on the Company's commitment to providing safe, reliable, affordable, and increasingly clean natural gas for Michigan, and outlines the goal to achieve net-zero methane emissions by 2030.

[4] https://www.michigan.gov/whitmer/news/state-orders-and-directives/2020/09/23/executive-directive-2020-10
[5] https://www.energy.gov/topics/net-zero-economy

Q. Please explain the annual target setting process.

A. Targets for the EICP operational goals are proposed by subject matter experts, leveraging industry benchmarking, best practices, long-term strategies, annual work plans, and historical performance data. These targets are then recommended to the Company's officer team to validate that targets are both challenging and achievable and will result in the delivery of customer value. The officers present recommendations to the Board of Directors for final approval.

Q. Has the Company quantified customer benefits that are tied to EICP?

A. Yes. Although specific quantification of the benefits is not easy to perform for every metric, the Company has evaluated direct quantitative benefits of customers for three key operational goals: Employee Safety, Electric Reliability, and Culture Index. The Company has assessed indirect and/or qualitative benefits associated with the other goals.

Q. Is there a direct tie between the design of the EICP operational goals and desirable benefits for customers?

A. Yes. There is a direct tie between the design of the EICP operational goals and desirable benefits for customers.

The operational goals focus on delivering customer value through safe, reliable, affordable, and clean energy services—all desirable benefits for customers.

Q. Do you believe that benefits to customers from the EICP goals will, at a minimum, be commensurate with the programs' costs?

A. Yes. Company witness Conrad and I present evidence in support of including EICP costs at the 100% payout level, proving that including these costs will not result in excessive rates, and the costs of the EICP will, at a minimum, be commensurate with the programs'

costs. Company witness Conrad discusses various benefits to customers from the design of the Company's EICP. In addition, there are both quantitative and qualitative benefits to the successful achievement of these goals. The design of the EICP clearly leads to lower costs and improved service which benefit customers.

Q. How have you evaluated the EICP goals' direct quantitative benefits?

A. The direct quantitative benefits associated with Employee Safety, Electric Reliability, and Culture Index have been calculated. For each of these metrics the Company uses a four-year historical average baseline. The first of those metrics is Employee Safety. The Employee Safety goal for 2025, when met, will reduce incidents by 34% from the four-year historical average. The resulting reduction in lost workdays and medical expenses is $1,278,673 of annual direct savings. Expected indirect savings, calculated using OSHA's recommended multiplier, totals $889,864 of annual savings. Together, the projected annual direct and indirect savings that accrue to the benefit of the customer totals $2,168,537. Exhibit A-157 (AEM-2) provides the calculation of these savings.

The second metric that can be readily translated to quantifiable cost avoidance for customers is in electric reliability. Using cost per outage minute estimates from Berkeley Labs[6], the 8.0-minute average annual reduction in outage minutes from the four-year historical performance has resulted in annual economic benefits to customers more than $25,115,262. Exhibit A-158 (AEM-3) provides the calculation of these savings.

Third, there are benefits related to the Culture Index created by reducing employee turnover for Company employees with <1-4 years of tenure by 2% as compared with industry peers. The average annual salary of an employee with tenure of <1-4 years of

[6] https://www.osti.gov/servlets/purl/963320

experience is $99,990, and lower turnover avoids costs equal to at least 1.5 times the employees' annual salaries. This means that by reducing turnover in this employee group by 2%, when compared to utility peers, the Company will avoid costs of $7,064,260. Exhibit A-159 (AEM-4) shows the calculation in further detail.

Q. How have you evaluated the EICP goals' other qualitative benefits?

A. The Methane Emission Reduction goal is essential to achieving the Company's goal of net-zero methane emissions from its natural gas system by 2030, which supports the Michigan Governor's goal for Michigan to achieve economy-wide net-zero greenhouse gas emissions, and to be carbon neutral by 2050. The direct economic benefits for customers are difficult to calculate, but the qualitative benefits are beyond dispute. Improved Customer Experience is another benefit of achieving EICP goals that is difficult to quantify but nonetheless quite real. The benefits of pursuing improvement in Customer Experience have been discussed above.

Q. Why have you included both electric and natural gas benefits in your quantification?

A. Consumers Energy's utility operations are combined in one organization and operational goals are established in critical areas to drive the delivery of customer value through safe, reliable, affordable, and clean energy services across electric and natural gas operations. The quantified benefits of Employee Safety, the Culture Index, and Electric Reliability show that benefits to electric customers clearly exceed the employee incentive compensation amounts that Consumers Energy has requested be included in rates in this case.

Q. What is the Company's reasoning for having a Methane Emission Reduction goal attributed to electric business employees?

A. The EICP goals align with Company priorities, providing targets for the entire organization. Prioritizing Electric Reliability and Methane Emission Reduction is essential, as previously mentioned in my testimony. The Company quantifies EICP benefits to ensure electric customers pay for the benefits they receive. Given the combined operations, and the majority of non-union employees supporting both electric and gas operations, it is reasonable to include both Electric Reliability and Methane Emission Reduction goals in the EICP.

Q. What portion of the direct benefits that you have quantified above do you conclude benefit electric customers?

A. A portion of the quantified benefits in Employee Safety and the Culture Index directly benefit electric customers. By allocating 60% of these combined customer benefits, the Company calculates annual savings for electric customers as follows: $1,301,122 from Employee Safety, $4,238,556 from avoided turnover costs associated with the Culture Index. Additionally, the full customer benefit of $25,115,262 from Electric Reliability impacts all electric customers. This totals $30,654,930 in value specifically for electric customers, far exceeding the total costs of the EICP allocated to electric customers.

Q. Why did you use a 60% allocation to evaluate benefits to electric customers?

A. The 60% allocation is based on the total number of electric employees as a percentage of total number of Consumers Energy employees. Using the percentage of total employees is a reasonable methodology to allocate the Employee Safety and Culture Index benefits identified above.

Q. Should the Company be pursuing these benefits independent of the EICP?

A. Yes. The EICP takes this into consideration. As discussed by Ms. Conrad in her direct testimony, incentive mechanisms help communicate priorities, engage employees in business success, reward valued skills and behaviors, and create business understanding for employees. The EICP is structured in a way that focuses employees on delivering customer value through continuous improvement. Making it clear to employees that a portion of their market-based compensation is at risk and depends upon their collective ability to meet these targets emphasizes the importance of goal achievement and encourages coworkers to deliver their best performance.

Q. Do you believe that the EICP is the reason that the above benefits have been realized?

A. Yes. I believe the design of the EICP is intended to and does make it significantly more likely customer benefits will be achieved by establishing operational goals to improve the Company's ability to continuously improve the delivery of customer value through safe, reliable, affordable, and clean energy services. By placing a portion of employees' market-based compensation at-risk, employees are incentivized to meet the EICP operational goals.

Q. Are you confident the Company can consistently achieve 100% targets on the EICP operational goals?

A. Yes. The four-year historical average for goal achievement illustrates that the Company and its employees have consistently achieved 115% of the targets associated with the EICP operational goals. Refer to Exhibit A-156 (AMC-1) for EICP Operational Performance Metrics for the operational goals and targets in 2024 and 2025.

Q. Do you believe that any of the metrics included in the EICP are duplicative?

A. No. The metrics have been selected to create a designed, balanced focus on safety, reliability, and employee culture that results in broad customer benefits.

Q. Does this conclude your direct testimony?

A. Yes.

MR. GENSCH: Thank you, Your Honor. Next we have the company witness Megan L Jerore, who originally filed direct testimony under the name Megan Metz, Ms. Jerore's direct testimony consists of a cover page and 27 pages of questions and answers, and she also had rebuttal testimony consisting of a cover page and four pages of questions and answers. And Ms. Jerore's sponsored Exhibits A-160, A-161, and A-162.

THE COURT: Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct and rebuttal testimony of Megan Jerore is bound in the record and Exhibits A-160 through A-162 were admitted.

(At 3:02 p.m., Exhibits A-160 through A-162 were admitted)

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

MEGAN L. METZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Megan L. Metz, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. In what capacity are you employed?

A. I am the Director of Electric Supply Operations and Power Supply Cost Recovery ("PSCR") within the Electric Supply Organization.

QUALIFICATIONS

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science degree in Industrial and Operational Engineering from University of Michigan in 2002 and a Master of Business Administration degree from Spring Arbor University in 2007. I have been employed by Consumers Energy since 2002, in roles primarily related to Electric Generation and with increasing levels of responsibility. From 2002 to 2010, I held engineering positions in Production Cost Modeling, Fuel Supply, Plant Operations, and Strategy Development. From 2010 to 2013, I was Plant Compliance and Economic Analysis Director, responsible for coordinating the long-term financial plan and budget for all Electric Generation, economic analysis of projects, outage scheduling and environmental, health & safety and North American Reliability Corporation ("NERC") compliance. From 2013 to 2014, I was Production Engineer at the J.H. Campbell 1 and 2 facility, performing outage management and operations support and supervision. From 2014 to 2017, I was the Fuel Procurement Director, responsible for purchasing coal and gas for Consumers Energy's generation facilities. From 2017 to 2020,

I was Director of Electric Regulatory Compliance, responsible for Federal Energy Regulatory Commission ("FERC"), NERC, Michigan Public Service Commission ("MPSC" or the "Commission") Electric Code, and Midcontinent Independent System Operator, Inc. ("MISO") regulation compliance. From 2020 to present, I have been the Director of Merchant Operations and PSCR, responsible for the Company's Merchant Operations center which is a 24x7 control center that interfaces with MISO and manages dispatch electric generation to meet customer load. In addition, I am responsible for production cost modeling and managing the Company's generation capacity through the MISO Planning Resource Auction ("PRA").

Q. Have you previously provided testimony before the Commission?

A. Yes. I provided testimony in the following cases:

- MPSC Case No. U-21389, Consumers Energy 2023 Electric Rate Case;
- MPSC Case No. U-21585, Consumers Energy 2024 Electric Rate Case; and
- MPSC Case No. U-21647, Consumers Energy 2023 Demand Response Reconciliation.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is: (i) support PSCR costs expected to be incurred during the test year period beginning from May 1, 2026 and ending April 30, 2027; (ii) discuss the Company's State Reliability Mechanism ("SRM") capacity charge inputs, cost offsets, demand, and reconciliation; (iii) provide an update of MISO's Seasonal Resource Adequacy Construct; (iv) support the value of continued investment in the Company's generation assets; (v) support the value of the Company's Demand Response ("DR") programs; and (vi) present and support the value of upgrades to PCI Energy Solutions ("PCI") software.

Q. How is your testimony related to the testimony of other Company witnesses?

A. Company witness Eugene M. Breuring's direct testimony ties to the PSCR costs, Large Economic Development Rate ("LED"), and Long-Term Industrial Load Retention Rate ("LTILRR") revenues. Company witness Emily A. Davis discusses the SRM charge and how the SRM relates to the Cost of Service. Company witness Richard T. Blumenstock describes the Company's generation asset investment plan. Company witness Alex M. Gast addresses the Company's planned spending and growth of DR programs. Company witness Thomas P. Clark supports Integrated Resource Plan ("IRP") Settlement storage projects.

Q. Have you prepared any exhibits in conjunction with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-160 (MLM-1)	Power Supply Cost Recovery Forecast for May 1, 2026 – April 30, 2027;
Exhibit A-161 (MLM-2)	Consumers Energy Forecast – Energy Market Sales Revenue and Total Variable Expense; and
Exhibit A-162 (MLM-3)	Summary of PPA Changes from September 30, 2024 – February 1, 2025.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

POWER SUPPLY COST RECOVERY

Q. Please explain power supply charges applicable to the Company's customers.

A. Power supply charges are applicable to the Company's full-service customers only. Full-service customers receive power supply service, including generation and transmission costs, as well as delivery service from the Company. Retail Open Access

("ROA") customers only receive delivery service from the Company and obtain their power supply service from an authorized alternative electric supplier.

Q. Are the Company's power supply costs recoverable?

A. Yes. All the Company's reasonably and prudently incurred power supply costs are recoverable. Power supply costs are forecast in an annual PSCR Plan filing with the MPSC and subsequently reconciled in a related annual PSCR Reconciliation filing with the MPSC. Forecasting, reconciliation, and recovery of PSCR costs is governed by Michigan statute, MCL 460.6j, 1939 PA 3.

Q. Please explain how PSCR-related costs are included in this filing.

A. PSCR costs are included in this filing as a forecast of expenses for the projected test year beginning May 1, 2026 and ending April 30, 2027. PSCR expenses are recovered monthly from full-service customers through a PSCR factor as described and estimated in this case by Company witness Breuring. A portion of the PSCR expenses related to the cost of capacity are utilized to calculate the SRM charge as discussed by Company witness Davis and as discussed later in this direct testimony.

Q. Please explain Exhibit A-160 (MLM-1).

A. Exhibit A-160 (MLM-1) is the forecast of the Company's generation requirements, transmission expenses, and purchased and interchange expenses for the projected test year ending April 30, 2027. The total system requirements represent the projected total energy supply requirements, presented in MWh, to serve customer load. The total system requirements are projections of energy production (or consumption) based upon generation requirements from energy load forecasts, unit heat rates, maintenance schedules, unit random outage rates ("RORs"), fuel costs, and unit net demonstrated capabilities. Variable

expenses are a forecast based upon the projected MWh, commodity price forecasts, power purchase agreement ("PPA") variable cost provisions, and renewable energy transfer costs. Total capacity and non-utility generator ("NUG") costs are based upon the capacity forecast for the Company and approved contract terms of the contracts. Also included are MISO cost projections for transmission and energy markets administration, as well as chemical reagent costs based upon generating unit energy production forecasts. The LTILRR revenues, and the LED Rate, lines 43 and 44, respectively, of Exhibit A-160 (MLM-1) are shown separately such that the forecasted total power supply costs recovered from the remaining full-service customers can be shown on line 45 of Exhibit A-160 (MLM-1). The total power supply cost levels are consistent with prior years.

Q. How were the values in Exhibit A-160 (MLM-1) derived?

A. The values were derived from the Aurora Production Costing Program ("Aurora"), which was the same platform used in the Company's 2021 IRP filing, Case No. U-21090. Aurora is a computer software application developed by Energy Exemplar ("EE") that supports electric utility decision analysis and corporate strategic planning. Aurora simulates the dispatch of the Company's generating resources, purchased power resources, and interchange power resources to meet projected customer electric demand requirements. The projected customer electric demand requirements are discussed in further detail in Company witness Breuring's testimony.

The primary inputs to Aurora are projected system loads, unit heat rates, maintenance schedules, unit RORs, fuel costs, unit net demonstrated capabilities and purchased and interchange ("P&I") power availability and costs. The model used by Aurora is structured to align as closely as possible with the way that MISO operates and

administers the energy market. The system load and system generation requirements data were provided by Company witness Breuring. Coal, oil, and natural gas costs were provided by the Company's Fossil Fuel Supply Group. Information about the Company's generating units was provided by the Company's Plant Operations Group and discussed in the testimony of Company witness Blumenstock.

The primary outputs yield a monthly cost amount for: (i) each unit of energy in the system requirements; (ii) any variable expenses; (iii) capacity, fixed and purchased NUGs costs; as well as (iv) power supply costs, value of delivered energy, total expenses, and any revenue credits. This model is also used to develop the Company's presentation in its annual PSCR Plan cases.

Q. What expenses are included in the PSCR forecast?

A. PSCR expenses include both fixed and variable expenses. Variable expenses include, but are not limited to, fuel expense, variable purchased energy, and MISO interchange, as well as a portion of the Company-owned facilities included in the Renewable Energy Plan ("RE Plan"), as shown on lines 15 through 26 of Exhibit A-160 (MLM-1). Fixed expenses include, but are not limited to, purchases of fixed energy and capacity, as well as renewable energy transfer costs for a portion of the Company-owned facilities included in the RE Plan, as shown in lines 28 through 33 of Exhibit A-160 (MLM-1).

Q. Please explain any difference between the 2026 and 2027 forecasts filed as part of the 2025 PSCR Plan filing, and the forecast presented in this electric rate case filing.

A. The PSCR costs are included in this filing as a forecast of expenses for the projected test year beginning May 1, 2026 and ending April 30, 2027 as opposed to the full 2025 calendar year cost projections presented in the 2025 PSCR Plan filing (Case No. U-21592).

Additionally, updated information for all main inputs mentioned above were included in a February 2025 update of the PSCR model previously utilized in support of the 2025 PSCR Plan. Changes include updated forecasts for electric sales, fuel pricing, generation outage schedules, and PPAs, including deferred commercial operation dates ("CODs") for PPAs due to various issues such as supply chain material delays and renewable site permitting challenges.

Q. Please detail the line items in Exhibit A-160 (MLM-1).

A. Total system requirements (expressed in units of MWh) for the projected test year ending April 30, 2027 are shown on page 1, line 14, and are based on projections provided by Company witness Breuring.[1] Category-level detail comprising the total system requirements is shown on page 1, lines 1 through 13, and is the output of the Aurora production cost modeling and supplied inputs mentioned above.

The total annual fuel and variable purchased and net interchange PSCR expense, excluding any fixed energy and capacity expense, is shown on page 1, line 27 (expressed in units of thousands of dollars). This information was derived using production cost simulations and inputs as previously discussed. Exhibit A-160 (MLM-1), lines 28 through 33, present the fixed and capacity-related costs included in PSCR expense.

Line 35 shows the projected transmission expense that is expected to be recovered as part of the Company's power supply costs in PSCR proceedings. In Case No. U-14274, the Commission ordered that transmission costs are approved for inclusion in the Company's PSCR Plan and Reconciliation filings.

[1] The small variance in total MWh between Exhibit A-160 (MLM-1) and Exhibit A-15 (EMB-2), Schedule E-1, is due to timing differences between production cost modeling and changes to generation requirements.

Lines 36 and 38 through 41 show reagent expenses for pollution control at the Company's fossil generation plants which are expected to be recovered as part of the Company's power supply costs in PSCR proceedings.

The total PSCR costs are shown on Exhibit A-160 (MLM-1), page 1, line 42. A portion of the PSCR expense is recovered under the LTILRR and a portion of the PSCR expense is recovered under the LED Rate. These amounts are shown on page 1, lines 43 and 44, and the remaining PSCR expense to be recovered from remaining full-service customers is shown on page 1, line 44.

Pages 2 and 3 of Exhibit A-160 (MLM-1) summarize the purchased and net interchange power volumes and corresponding expenses or revenues projected to be incurred by the Company in the projected test year. These pages detail the volume associated with purchases from NUGs and markets shown in the Total Received, page 2, line 50, with deliveries shown in the Total Delivered, page 2, line 53, category of Exhibit A-160 (MLM-1).

Q. Please explain the expenses for Company-owned resources included in the RE Plan.

A. In general, for most Company-owned resources, there is no fixed expense included in PSCR expenses. The exception[2] to this is presented on page 1, line 29, of Exhibit A-160 (MLM-1) where the Company-owned renewable capacity (or fixed-expense related) component of the transfer price associated with the Company's owned renewable resources is provided, complementing the energy (or Company-owned variable-expense related) component of the transfer price presented on page 1, line 19, of Exhibit A-160 (MLM-1).

[2] Fixed expense related to transfer costs is an allowable cost included in PSCR cases under Public Act 295 of 2008 ("Act 295"), as modified under Public Act 235 of 2023, the Clean and Renewable Energy and Energy Waste Reduction Act. MCL 460.1047(2)(b)(iv).

Q. Please explain how PPAs are structured.

A. PPAs include both fixed and variable costs. Some PPAs define payments as "capacity" payments, "fixed energy" payments, and "variable energy" payments. Capacity payments and fixed energy payments are generally regarded as fixed expense because they are expected to be incurred regardless of the amount of energy delivered by the supplier. Variable energy payments generally reflect the cost of purchasing a MWh of energy from a supplier and thus vary depending on the amount of energy delivered. Variable energy payments therefore are similar to the variable expense (e.g., fuel cost) associated with producing a MWh of energy at a Company-owned facility.

Some other PPAs provide for a single price to be paid for each unit of energy to be delivered based on a capacity price and a combined fixed and variable energy price. Generally, these types of contracts are not dispatchable by the Company, thus the amount to be paid is likely limited by the physical capability of the supplying facility. In these instances, we have estimated the fixed energy costs based on the rates upon which the contracts were originally modeled.

Under Act 295, other PPAs are included in the Company's rates based on the amount of cost allowed under state law to be transferred from the Company's Incremental Cost of Compliance to its PSCR costs through the transfer price mechanism. To estimate the amount of capacity, fixed energy, and variable energy expense associated with these transfer costs, the Company used the energy and capacity schedules approved by the Commission in Act 295 and through the Company's Annual Renewable Energy Cost Reconciliation Proceedings to determine the transfer expenses.

Energy or variable cost-related expense for the Company's PPAs is shown on Exhibit A-160 (MLM-1), page 1, line 25, labeled "Purchased (NUGs) Variable Cost." Capacity or fixed cost-related expense for the Company's PPAs is shown on Exhibit A-160 (MLM-1), page 1, lines 31 and 32, labeled "Purchased (NUG) Capacity" and "Purchased (NUG) Fixed Energy," respectively.

Q. For line items 28 through 33 shown on Exhibit A-160 (MLM-1), what are the fixed expenses in the PSCR forecast?

A. The Company is forecasting $2,288,633,000[3] of PSCR expense expected to be incurred during the projected test year ending April 30, 2027, of which $366,140,000[4] is fixed expense.

Q. Are the projected fuel expenses and the projected purchased and interchanged power expenses shown on Exhibit A-160 (MLM-1) subject to any uncertainty?

A. Yes. The expenses are based on projections made by the Company of fuel costs, customer demand, generating unit availability, P&I power availability, P&I power prices, inflation, and other factors that cannot be predicted with precision. These projections were based on the best available information at the time the production cost modeling was completed to support this proceeding. It follows that any results from the use of these projections provide a reasonable but uncertain estimate of power supply costs.

[3]See Exhibit A-160 (MLM-1), page 1, line 42, column (o).
[4]See Exhibit A-160 (MLM-1), page 1, line 34, column (o).

Q. What has been the Company's recent experience with the delivery of new construction PPAs?

A. The Company has experienced changes to five PPA's since September 2024, as listed in Exhibit A-162 (MLM-3). Of the five PPAs, three were terminated and two requested COD delays, with CODs requested for later in 2026.

Q What is your understanding of the basis for the delays and cancellations of PPAs?

A. It is my understanding that the two primary causes of the delays and cancellation of PPAs are supply chain disruptions and site permitting. Extensive delays and cost increases associated with the procurement of renewable energy system components have led to project delays and/or cancellations. In addition, various entities have contested the site permitting for renewable energy systems, further exacerbating the supply chain issues.

Q. What are possible effects of delayed CODs for PPAs on power supply costs?

A. For delays in those PPAs providing capacity in the form of Zonal Resource Credits ("ZRCs"), those delays could result in fewer ZRCs being available for satisfying the Company's capacity requirement in the MISO PRA and may require the Company to procure capacity from the PRA or some other means to meet the Company's Planning Reserve Margin Requirement ("PRMR"). So, while the Company would realize the cost of capacity from the PRA, the PSCR costs would decrease by the amount of the delayed PPA.

Q. Please describe the practices and procedures used by the Company to protect customers from PPA cost escalation or COD delays.

A. To protect customers from PPA cost escalation, price is defined as a term of the contract upon execution. If a counterparty requires a price increase to make the project viable, the

Company assesses the amendment request and specifics of the situation and compares other alternatives to determine if the amendment is in the best interest of customers. To protect from COD delays, the contract generally includes penalties, up to and including termination of the contract.

Q. Please summarize your direct testimony regarding power supply charges.

A. The Company anticipates incurring approximately $2,288,633,000[3] in total PSCR expenses during the projected test year ending April 30, 2027, of which $121,588,000[5] is expected to be recovered under the LTILRR, $63,092,000[6] is expected to be recovered from LEDR, and $2,103,953,000[7] is expected to be recovered from remaining full-service customers.

SRM – CAPACITY CHARGE REVENUE OFFSETS AND DEMAND

Q. Please describe the SRM Capacity Charge.

A. In the Commission's November 21, 2017 Order in Case No. U-18239 ("November 21 Order"), the Commission adopted a methodology for determining the SRM Capacity Charge pursuant to Public Act 341 of 2016. The capacity charge "is a retail rate, designed to recover the incumbent utility's cost of providing capacity service, to whatever type of customer load – bundled or choice" (November 21 Order, page 73) to ensure long-term resource adequacy to customers in the state.

Q. How is the capacity charge determined?

A. Company witness Davis's direct testimony describes how the capacity charge is calculated and what inputs are utilized in the calculation. As discussed in Company witness Davis's

[5] See Exhibit A-160 (MLM-1), page 1, line 43, column (o).
[6] See Exhibit A-160 (MLM-1), page 1, line, 44, column (o).
[7] See Exhibit A-160 (MLM-1), page 1, line 45, column (o).

direct testimony, the SRM Capacity Charge calculation includes capacity cost offsets and a capacity charge demand used as the denominator of the capacity charge. These inputs rely on data that is detailed in this direct testimony below.

Q. Please define capacity cost offsets.

A. Capacity cost offsets are projected revenue(s) and associated fuel costs that are subtracted from the calculated capacity-related cost in developing the SRM Capacity Charge.

Q. Please identify the capacity cost offsets.

A. The capacity cost offsets used in the SRM calculation are:

(i) Energy Market Sales Revenue of $871,945,000 (line 12, Exhibit A-161 (MLM-2));

(ii) Off-System Energy Sales of $9,000,000;[8]

(iii) Ancillary Service Sales of $5,000,000;

(iv) Bilateral Energy Sales of $0; less

(v) Related Fuel Costs of $545,993,000 (line 24, Exhibit A-160 (MLM-1)).

Q. What is the basis for the above capacity cost offsets?

A. The Energy Market Sales offset is derived from the monthly volume of energy produced by generators owned or controlled by the Company as extracted from the Company's forecast of power supply costs for the projected test year (sum of lines 1 through 8 and lines 10 and 12 in Exhibit A-160 (MLM-1)) multiplied by the Company's forecast of the average monthly locational marginal price. The Off-System Energy Sales offset is based on the actual 2024 energy sales made to the Company's sole non-jurisdictional wholesale customer. The Ancillary Service Sales offset is based on the most recent-year historical value in this case. The Company made no bilateral energy sales in 2024 and does not

[8] 2024 Actual Off-System Energy Sales, Ancillary Service Sales and Bilateral Energy Sales from Case No. U-21424, Exhibit A-30 (RTS-3) line 2, lines 3-4, and line 5, respectively.

forecast to make any bilateral energy sales in the projected test year ending April 30, 2027. Related Fuel Costs are the forecasted variable costs associated with the volume of Energy Market Sales as extracted from the Company's forecast of power supply costs for the test year (Exhibit A-160 (MLM-1), page 1, line 24).

Q. Is the Energy Market Sales offset the same as the Net Interchange Credits shown on Exhibit A-160 (MLM-1), page 3?

A. No. The Energy Market Sales offset is representative of the energy market value of the Company's entire generation fleet and PPAs and is calculated by multiplying the monthly energy produced by those resources by the forecasted average monthly locational marginal price. The Net Interchange Credit is the energy revenue of the generation fleet and PPAs sold into the MISO energy market in excess of the Company's load as calculated on an hourly basis. The Net Interchange Credit has been steadily declining over previous years due to reduced sales and increased load. The two numbers explained above are derived from the same PSCR model (Aurora) and start from the same data source but are calculated and utilized differently in the filing.

Q. What is the value and source for the Capacity Charge Demand used in the SRM Capacity Charge calculation?

A. The Capacity Charge Demand value is 9,853 MW. This value represents Consumers Energy's actual total supply, including ROA, recorded in 2024. This value is sourced from the Company's most recent Securities and Exchange Commission Form 10-K filing, consistent with the Commission's determination in Case No. U-20963.

Q. What is the resulting SRM Capacity Charge that is proposed in this case?

A. As described by Company witness Davis, the SRM Capacity Charge calculation that is being proposed in this case is $116.17/MW-day.

Q. How does the SRM Capacity Charge proposed in this case compare to the SRM Capacity Charges approved in prior rate cases filed by the Company?

A. The SRM Capacity Charge approved was: $65.13/MW-day in Case No. U-21585; $76.62/MW-day in Case No. U-21389; $244.80/MW-day in Case No. U-21224; $328.26/MW-day in Case No. U-20963; and $374.95/MW-day in Case No. U-20697.

Q. Have there been any proposed revisions to the SRM Capacity Charge calculation in previous cases?

A. Yes. In several previous cases, including Case Nos. U-20697, U-20963, U-21389, and U-21585, the Company proposed to use the ZRC value assigned to the Company's capacity resources in the denominator of the SRM Capacity Charge. In Case No. U-20963 the Company proposed to amend an input for the Capacity Cost Offsets calculation, more specifically to include variable expense incurred by PPAs in the Related Fuel Costs offset. Additionally, in Case No. U-21585, Staff witness Nicholas M. Revere proposed that the SRM Capacity Charge calculation include an offset for the Company's net sales, effectively reducing the capacity cost for the Company, and ultimately ensuring unnecessary cost burden is not passed on to the customer.

Q. Were the SRM Capacity Charge calculation changes proposed by the Company approved by the Commission?

A. No. The proposals were rejected by the MPSC, based on the argument that the method for calculating the SRM Capacity Charge was originally approved in Case No. U-18239 and

that any proposed changes to the calculation methodology would require that case be re-opened.

Q. Has the Company proposed any revisions to the SRM Capacity Charge calculation in this case?

A. No. The Company has not proposed any changes to the SRM Capacity Charge calculation in this case. However, following the Commission's prior guidance, the Company intends to further evaluate re-opening the original SRM Case No. U-18239 to propose a calculation methodology that does not result in a SRM Capacity Charge that prevents recovery of the Company's full capacity costs and, as a result, unfairly harms full-service customers. Additionally, the introduction of MISO's new Seasonal Construct, as I describe later in this direct testimony, will also impact the need to change the SRM Capacity Charge calculation's current calculation methodology.

Q. What is the SRM reconciliation calculation?

A. Per Section 6w(4) of Act 341, the SRM reconciliation calculation or "true-up mechanism" shall reconcile the differences between projected and actual net revenues of energy market sales above the Company's service requirements, fuel costs, and capacity costs. Should an SRM Capacity Charge be imposed, any over/under collection will be corrected in the subsequent year's capacity charge.

Q. Has the Company included the SRM reconciliation amount in this proceeding?

A. Yes. Although the Company has never implemented the SRM Capacity Charge, as ordered by the Commission in Case No. U-21585, the Company has included the SRM reconciliation amount, as shown on line 19 of Company witness Davis's Exhibit A-16 (EAD-2), Schedule F-1.1.

ELECTRIC GENERATION CAPACITY

Q. In his direct testimony, Company witness Blumenstock proposes capital investment and operating and maintenance expenses necessary to support the Company's electric generation fleet. Why is this spending important for the Company's customers in the context of electric supply and capacity planning?

A. As Company witness Blumenstock explains in his direct testimony, the Company owns a diverse electric generation fleet comprised of fossil fuel, renewable (including hydroelectric), and pumped storage assets. These assets are prudently managed and operated to ensure the supply of reliable and cost-effective electricity for customers. Continued investment and spending in the generation units are necessary to maximize the economic benefit delivered to customers in the form of both energy and capacity value. Company witness Blumenstock provides a description of Net Energy Value ("NEV"), which the Company utilizes to analyze and quantify a generation asset's net benefit (relative to cost) to the Company's customers on an energy basis. From a capacity perspective, maintenance of the generation fleet is necessary to ensure the Company can meet resource adequacy obligations with MISO, as further described below. Both the energy and capacity value of the generation units ultimately underpin the power supply costs as presented earlier in this direct testimony.

Q. What is the connection between the generation reliability spending proposed by Company witness Blumenstock and the capacity from those assets?

A. As discussed by Mr. Blumenstock, generation reliability investments are expected to maintain or improve unit availability and reliability. Improvements in unit availability are expected to produce a corresponding improvement in the Seasonal Accredited Capacity

("SAC") for those generating units. SAC is defined within the MISO Resource Adequacy Business Practice Manual BPM-011[9] as the anticipated capacity and availability of planning resources during times when they are most needed. Improvement in SAC and ensuring unit availability translate into increased capacity credit received from MISO in the form of ZRCs as well as increased NEV for the generating units. Company witness Blumenstock provides additional discussion on the value of minimizing ROR and improving generating unit availability. The increased capacity credit is part of the Company's plans for meeting future PRMR and reducing cost associated with the need to purchase third-party or market based ZRCs.

Q. Please explain the MISO seasonal resource adequacy construct?

A. On August 31, 2022, FERC accepted MISO's proposal to implement seasonal resource adequacy requirements effective for the 2023/2024 planning year (see Case No. ER22-495-000, et al.). MISO's "seasonal construct" requires Load Serving Entity's ("LSEs") to meet the peak demand and load requirements for one peak hour per season (Summer, Fall, Winter, Spring). Summer season is defined as June 1 through August 31, Fall season is defined as September 1 through November 30, Winter season is defined as December 1 through last day in February, and Spring season is defined as March 1 through May 31. MISO's stated intended outcomes of moving to a Sub-Annual Resource Adequacy construct are to (1) identify reliability needs unique to each season, (2) align resource availability with seasonal needs, and (3) facilitate seasonal outages or partial year operations.

[9] Available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/, accessed October 01, 2024.

In addition to the change from an annual to a sub-annual construct, MISO also changed the capacity accreditation methodology for thermal generating units and DR Resources. The capacity accreditation methodology changed from an Unforced Capacity, summer-focused construct, to a two-tier system based on real-time availability, with emphasis on the highest risk periods for each season. MISO has not changed the capacity accreditation methodology for non-thermal resources currently, except to adjust for seasonality.

Q. Please explain PRMR.

A. The PRMR is defined by MISO in the Resource Adequacy Business Practice Manual BPM-011 as the number of MW in ZRCs required to meet a LSEs Resource Adequacy Requirements ("RAR"). The RAR is established to ensure that LSEs have enough Planning Resources to reliably serve load for the applicable seasons. Consumers Energy is an LSE and is required to maintain sufficient capacity to ensure adequate electric supply in each Planning Year period for the projected LSE's load. The Company relies on MISO to determine the appropriate PRMR Consumers Energy should maintain. The PRMR is calculated by MISO using: (i) the Company's forecast peak load coincident to MISO's peak load; (ii) a transmission loss percentage applicable to the Company; and (iii) a reserve margin to ensure reliability.

Q. Please explain what a ZRC is and how ZRCs are currently awarded for the Company's generation assets.

A. For thermal generation resources, a ZRC is a capacity credit increment equal to 1 MW of generation resource, adjusted by its availability which is based on the SAC calculation. The SAC calculation reflects the anticipated capability and availability of a generation

resource during times when they are most needed. This two-tier weighing structure is based on its real-time offered availability during seasonal Resource Adequacy ("RA") hours (Tier 2) and Non-RA hours (Tier 1). Resource Adequacy hours are based on emergency events, the tightest operating margin hours and maximum operating margin threshold. Operating margin is the amount of MW available divided by the amount of system load.

For intermittent generation resources, a ZRC is a capacity credit increment equal to 1 MW of generation resource, adjusted by its availability, which is based on historical performance during critical hours within each season, where new resources receive class average for that resource type until required historical data is accrued.

For reservoir hydroelectric facilities such as Ludington Pumped Storage, a ZRC is a capacity credit increment equal to 1 MW of generation resource, adjusted by its reliability, which is based on the Demand Equivalent Forced Outage Rate ("EFORd") calculation. Over each three-year period, startup, run time, and outage information is collected and categorized to determine the EFORd value for each generator. Prior to each Planning Year, MISO awards ZRCs to generator owners based on the lesser of the interconnection service limit and the Generation Verification Test Capacity ("GVTC"), multiplied by the result of one minus EFORd.

Q. What is the ultimate effect of obtaining ZRCs for generating units?

A. The Company's sustained capital investment in generator reliability allows the Company to maintain or improve the availability of its units and, as a result, maintain or increase the amount of ZRCs and the corresponding value realized to customers in the future. These ZRCs are a key component of meeting the Company's PRMR and mitigating customer

exposure to capacity price risk from insufficient capacity resources to meet the Company's PRMR.

Q. Please describe the result if no additional investments are made.

A. If no additional investments are made, the deterioration of a plant's reliability is expected to increase over time, reducing the ZRCs assigned to the generating unit and therefore reducing the capacity value of the facility.

Q. How is capacity value determined?

A. MISO administers a PRA annually, which "clears" seasonal ZRC offers to satisfy 100% of seasonal PRMR for each LSE. If sufficient resources are not available, the PRA cost of capacity may be driven as high as Cost of New Entry ("CONE"). CONE is an industry-wide concept that represents the fixed costs of constructing and operating a new source of power to provide capacity. In the case of MISO, CONE represents the cost of constructing and operating a new simple cycle gas turbine fueled generator.

Q. At what cost has the CONE been set in recent years?

A. The CONE has been set at the following costs in recent years for MISO Zone 7:

- Planning Year 2021/2022: $259.73/ZRC-day;
- Planning Year 2022/2023: $236.66/ZRC-day;
- Planning Year 2023/2024: $289.37/ZRC-day;
- Planning Year 2024/2025: $347.36/ZRC-day; and
- Planning Year 2025/2026: $358.71/ZRC-day.

Q. For comparison, what was the clearing price for capacity in MISO Zone 7 for each of the above Planning Years?

A. MISO Zone 7 cleared at the following prices in recent years:

- Planning Year 2021/2022: $5.00/ZRC-day;

- Planning Year 2022/2023: $236.66/ZRC-day;
- Planning Year 2023/2024:
  - Summer Season: $10.00/ZRC-day;
  - Fall Season: $15.00/ZRC-day;
  - Winter Season: $2.00/ZRC-day; and
  - Spring Season: $10.00/ZRC-day.
- Planning Year 2024/2025:
  - Summer Season: $30.00/ZRC-day;
  - Fall Season: $15.00/ZRC-day;
  - Winter Season: $0.75/ZRC-day; and
  - Spring Season: $34.10/ZRC-day.

Q. If the cost of capacity were to go to CONE, how would the Company's capacity cost be affected?

A. If MISO Zone 7 clears at CONE, as it did in Planning Year 2020/2021 and Planning Year 2022/2023, it is a signal that the Zone does not have enough capacity to meet the Zone's PRMR, which in turn means that there is an increased risk of system-wide reliability issues. If the Company is a net purchaser of capacity in a given year, an Auction Clearing Price of CONE could result in price increases to the Company's customers.

Q. What conclusion have you reached relative to the generation spending being sponsored by Company witness Blumenstock?

A. The capital investment in the Company's generation fleet will provide for reliable and cost-effective power supplied to customers. This is true for both energy and capacity, where capacity is particularly necessary to meet resource adequacy obligations (i.e. PRMR) and avoid purchasing potentially high-cost capacity from the MISO capacity market.

DEMAND RESPONSE CAPACITY

Q. Please explain the types of DR programs expected to be employed by the Company in 2025 and 2026.

A. The Company's DR programs planned for 2025 and 2026 fall into one of two categories: (1) those that are directed by the Company; or (2) those that are dependent upon customer behavioral choices. DR programs controlled by the Company supply either a fixed quantity or range of energy. DR programs that are dependent upon customer behavioral choices provide energy reduction driven by rate structures that incentivize customers to use less energy during peak electric load periods. Additional details for specific DR programs are provided in the direct testimony of Company witness Gast.

Q. How are DR programs valued in terms of capacity credit in MISO's capacity market?

A. ZRCs are awarded by MISO for the Company's DR programs that are directed by the Company and registered by the Company as a capacity resource. The ZRCs are used to satisfy the Company's annual PRMR. For DR programs that are dependent upon customer behavioral choices, the Company reduces its peak load forecast by the amount of the DR programs that are expected at peak load conditions. This reduction directly reduces the Company's PRMR.

Q. What are the forecasted DR Program levels for Planning Year 2025/2026 and 2026/2027?

A. For Planning Year 2025/2026 and 2026/2027, the Company will administer five DR programs that are controlled by the Company, including Air Conditioning Peak Cycling, Smart Thermostat Program, DR Contracts, DR Rate GI Reduce By, and DR Rate GI Reduce To. The total planned capacity of these DR resources to be registered with MISO

in the summer season is approximately 651 ZRCs in Planning Year 2025/2026 and 684 ZRCs for Planning Year 2026/2027.

Also, for Planning Years 2025/2026 and 2026/2027, the Company will continue demand-side management programs that are dependent upon customer behavior, including Dynamic Peak Pricing, Energy Waste Reduction, Conservation Voltage Reduction, and Residential Summer on-peak rate. The total of these programs is approximately 1,023 MW for Planning Year 2025/2026 and 1,144 MW for Planning Year 2026/2027.

Per the MISO standard practice for demand-side management capacity planning, ZRC values reflect the expected MW reductions plus adjustments for transmission losses, planning reserve margin, and load diversity factors.

Q. What is the approximate market value of these DR resources?

A. Consumers Energy's Planning Year 2025/2026DR portfolio is projected to total 651.4 ZRCs, valued at $62 million at an estimated value of capacity of $95,351/ZRC-Year.[10] Consumers Energy's Planning Year 2026/2027 DR portfolio is projected to total 684.3 ZRCs, valued at $65 million at an estimated value of capacity of $95,351/ZRC-Year. Similar to the generation capacity discussion earlier in this direct testimony, continued investment in growing the Company's DR programs is important to the Company's electric supply strategy (meeting PRMR obligations and avoiding potentially higher-cost market capacity purchases) and its broader Clean Energy Plan to further integrate cleaner supply and demand-side resources to cost-effectively meet customer demand.

[10] Based on 75% of MISO's calculated Planning Year 2024/2025 CONE.

Q. Are you supporting any projected capital expenditures for IT related projects in the test year?

A. Yes. I am supporting an IT project for the PCI platform named the Integrated Energy Management Platform Optimization project. The test year capital expenditure amount is $1,343,299 and the projected test year O&M is $507,797. These amounts are reflected in Exhibit A-12 (SHB-4), Schedule B-5.1, line 3, and Exhibit A-19 (SHB-3), line 1, respectively, from Company witness Stacy H. Baker.

Q. Please describe the PCI Platform.

A. PCI provides software the Company uses to fulfill the FERC requirement of communicating unit availability to MISO to efficiently buy and sell electricity in the wholesale market.

Q. Please describe the value of the planned capital IT investment in optimizing this platform.

A. The Integrated Energy Management Platform Optimization project will reduce data center assets running PCI by migrating from on-premises into cloud services. This will optimize vendor support, reduce on-going operational costs (upgrades, server maintenance), and allow the Company to leverage new cloud capabilities.

Due to PCI currently being on-premise, the Company is not able to leverage benefits of the functionality in the vendor's cloud hosting solution (Software as a Service ("SaaS")). The break/fix, maintenance, and upgrades of the current solution (including application and infrastructure) require Company resources and the associated labor expenses to support. In addition, the infrastructure platform requires additional licensing

and costs that the Company is planning to eliminate with the service moving from on-premise to the cloud.

This project creates value for the Company by: (1) utilizing the vendor's SaaS environment to provide efficiencies for timely operational support. As an example, IT currently sends PCI a database copy so they can replicate the Company's environment in the vendor's system. Moving to the cloud eliminates the need for this step, thus reducing resource needs, time, and increased support costs. (2) Freeing up resources for more value-add work. (3) Reducing CE maintained Oracle server footprint, retiring all existing infrastructure so no future maintenance or complex licensing requirements will be needed. (4) reducing IT labor support costs. (5) reducing ongoing networking equipment replacement and upgrade costs.

Q. What is the scope of this project?

A. The project scope includes: (1) planning and executing the data migration; (2) designing and configuring new and existing vendor SaaS components; (3) implementing integrations to COTS (Commercial Off-The-Shelf) and custom systems; (4) testing; (5) education and training from PCI, increasing the skills of the employees to leverage the new vendor SaaS services and create job aids and runbooks for the support teams; and (6) decommissioning old infrastructure.

Q. What alternatives were considered?

A. Alternatives considered include: (1) continue to use the on-premise installation of PCI. This alternative was not chosen due to the significant waste involved in maintaining the system, the inability to leverage cloud functionality, and the failure to decrease the reliance on Oracle servers. (2) Move to a different energy market platform. This alternative was

not selected because the different platform would have lesser options and would not be able to utilize PCI's bid to build process. (3) Move to the vendor SaaS. This alternative was selected as the Company will utilize the latest technology and optimize operational support.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

MEGAN L. JERORE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Megan L. Jerore (formerly Metz), and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same Megan L. Metz who previously submitted direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes. My initial testimony was filed under my former name Megan L. Metz. I have since gotten married and changed my legal name.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut or address positions in the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Laura Maio. In support of Staff witness Paul R. Ausum's proposed increase to Company witness Eugene M. Breuring's energy sales forecast, Staff witness Maio provided an updated calculation and proposed increase to power supply costs, based on the proposed sales increase. I am rebutting Staff witness Maio's increased power supply cost amount, should the Commission agree with proposed sales increase.

I will also rebut the direct testimony of Attorney General ("AG") witness Sebastian Coppola. I will address the argument that the Integrated Energy Management Platform Optimization project is too premature to include in this rate case.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

REBUTTAL OF STAFF WITNESS MAIO

Q. What was the power supply cost increase proposed by Staff witness Maio on Page 13, line 7 of her testimony?

A. The proposed power supply cost increase is$12,228,188, effectively increasing the present revenue to $13,663,096 and therefore decreasing the Company's revenue requirement.

Q. Do you agree with Staff witness Maio's calculation of the increase in power supply cost?

A. No. While Staff witness Maio's power supply cost calculation is a fair approximation of the increased Power Supply Cost Recovery ("PSCR") expense, for purposes of accuracy, it is overly simplified. The sales forecast provided by Company witness Breuring is just one of many inputs into Aurora, the Company's PSCR modeling software, that provides this forecast. Additional inputs are detailed in my direct testimony beginning on page 4, line 18.

Q. To the extent that the Commission agrees that the sales forecast shall be increased by 204,655 MWh, what do you propose the total amount of power supply costs adjustment should be?

A. The adjusted sales forecast was input to the original PSCR Aurora model, where all other inputs remained unchanged. The Aurora model redispatches supply to serve the revised load. Transmission costs related to the increased sales forecast was also calculated. The updated total power supply cost increases by $11,587,168 rather than $12,228,188 as proposed by Staff witness Maio.

REBUTTAL OF AG WITNESS COPPOLA

Q. Do you agree with AG witness Coppola's assessment on page 89, line 17 that including the Information Technology ("IT") project named Integrated Energy Management Platform Optimization in this rate case is premature because it is in the investment planning phase?

A. I do not. As supported by the rebuttal testimony of Company witness Stacy H. Baker, merely being in the investment planning phase does mean the project is uncertain. Once the funding is approved through the rate case, the project is expected to move forward as previously planned.

Q. Please restate the value this project offers in optimizing this platform.

A. The Integrated Energy Management Platform Optimization project will transition Payment Card Industry ("PCI") from on-premises infrastructure to cloud-based services. This migration will enhance vendor support, lower ongoing operational costs (such as upgrades and server maintenance), and enable the Company to take advantage of advanced cloud capabilities.

Currently, because PCI is hosted on-premises, the Company cannot utilize the full functionality offered by the vendor's cloud-hosted Software as a Service ("SaaS") solution. Maintaining the existing system requires internal resources for troubleshooting, maintenance, and upgrades, along with additional licensing costs tied to the infrastructure. These expenses are expected to be eliminated once the system is moved to the cloud.

- Leveraging the vendor's SaaS environment for more efficient and timely operational support—for example, eliminating the need to send database copies for replication.
- Freeing up internal resources for higher-value tasks.

- Reducing the footprint of Oracle servers maintained by the Company and retiring legacy infrastructure, thereby avoiding future maintenance and licensing complexities.
- Lowering IT labor support costs.
- Cutting expenses related to networking equipment upgrades and replacements.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

MR. GENSCH: Thank you, Your Honor. Next is company witness Heidi J Myers. Her direct testimony consists of a cover page and 32 pages of questions and answers. Ms. Myers also had rebuttal test consisting of a cover page and 19 pages of questions and answers and Ms. Myers sponsored Exhibit A-163.

THE COURT: Are there any objections to the admission that this testimony or this this exhibit?

Hearing none. The direct and rebuttal testimony of Ms. Myers is bound in the record and Exhibit A-163 is admitted.

(At 3:02, Exhibit A-163 admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-21870

DIRECT TESTIMONY

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Heidi J. Myers, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Revenue Requirements and Regulatory Affairs.

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Accounting in 2003 from Michigan State University. I received a Master of Business Administration degree in 2012 from the University of Michigan – Flint. I am also a Certified Public Accountant licensed in the state of Michigan.

Q. Please describe your professional experience.

A. From 2004 to 2008 and from 2012 to 2015, I was employed by the Michigan Public Service Commission ("MPSC" or the "Commission") as an auditor and later as the Manager of the Revenue Requirements section. From 2008 to 2012 and 2015 to 2017, I was employed by the Lansing Board of Water and Light ("BWL"). During my tenure at the BWL, I held the following positions: Senior Rate Analyst, Executive Financial Assistant, Field Services Supervisor, Manager of Human Resources, and Supervisor of Finance and Planning. I joined Consumers Energy in January of 2017 as a Principal Rate Analyst and was promoted to Director of Revenue Requirements and Analysis in March of 2018 and was promoted to Executive Director of Revenue Requirements and Regulatory Affairs in June of 2020.

Q. What are your responsibilities as the Executive Director of Revenue Requirements and Regulatory Affairs at Consumers Energy?

A. As the Executive Director of Revenue Requirements and Regulatory Affairs, I am responsible for regulatory stakeholder collaboration and project management for the development of regulatory filings and communications as well as managing and preparing studies related to the level of the Company's revenue requirements, including the preparation and monitoring of gas and electric rate case filings before the Commission and other financial analysis. In addition, I oversee the calculation of the Company's Gas Cost Recovery and Power Supply Cost Recovery ("PSCR") monthly billing factors. In addition, beginning in July of 2023, I assumed responsibility for cost, pricing, and regulatory policy.

Q. Have you previously filed testimony with the Commission?

A. Yes.

Q. Please state the proceedings you have been involved in.

A. I sponsored testimony in the following cases:

Case No. U-14347 – Consumers Energy electric rate case;

Case No. U-14547 – Consumers Energy gas rate case;

Case No. U-17087 – Consumers Energy electric rate case;

Case No. U-17473 – Consumers Energy securitization;

Case No. U-18322 – Consumers Energy electric rate case;

Case No. U-20102 – Consumers Energy electric credit A;

Case No. U-20103 – Consumers Energy gas credit A;

Case No. U-20134 – Consumers Energy electric rate case;

Case No. U-20165 – Consumers Energy Integrated Resource Plan ("IRP");

Case No. U-20286 – Consumers Energy electric credit B;

Case No. U-20287 – Consumers Energy gas credit B;

Case No. U-20309 – Consumers Energy calculation C;

Case No. U-20697 – Consumers Energy electric rate case;

Case No. U-20889 – Consumers Energy securitization;

Case No. U-21389 – Consumers Energy electric rate case;

Case No. U-21490 – Consumers Energy gas rate case;

Case No. U-21585 – Consumers Energy electric rate case;

Case No. U-21806 – Consumers Energy gas rate case;

Case No. U-21911 – Consumers Energy incentive/disincentive; and

Case No. U-21918 – Consumers Energy distribution Investment Recovery Mechanism ("IRM") reconciliation.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide an overview of the Company's electric general rate case. My testimony introduces many of the key proposals included in this case and discusses how these proposals support the Company's long-range plans to provide safe, reliable, equitable, affordable, and clean energy for its customers. In addition, I give a brief introduction to the Company's witnesses and the topics supported in their respective testimony and I discuss the requirements for the Company's next electric rate case (*i.e.*, this case) as set forth in the Commission's March 21, 2025 Order in Case No. U-21585 ("U-21585 Order"). Finally, I support the Company's proposed Distribution IRM and ratemaking issues related to the Company's river hydro assets.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-163 (HJM-1)	Distribution Investment Recovery Mechanism – Annual Revenue Requirement

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes.

COMPANY OVERVIEW

Q. Please provide a brief description of Consumers Energy and its service territory.

A. Consumers Energy is a combination electric and natural gas utility proudly serving Michigan residents and businesses for 139 years. The Company, through its dedicated employees, provides safe, reliable, affordable, and increasingly clean electricity to 1.9 million customers in all 68 of Michigan's counties in the Lower Peninsula. Consumers Energy's electric system is comprised of over 115,904 miles of distribution lines, 1,280 substations, and a diverse portfolio of generating plants located throughout the state. Consumers Energy is dedicated to achieving world-class performance delivering hometown service.

Q. Please briefly describe Consumers Energy's most recent Commission-approved electric general rate relief.

A. On March 21, 2025, the Commission issued an order in Case No. U-21585 that resulted in a $154 million annual increase in the Company's electric rates and collection of a $22 million surcharge over 12 months for deferred costs related to distribution investments made in 2023. The net revenue increase from the order was 3.8% overall and 4.5% for the residential customer class, effective April 4, 2025.

CASE OVERVIEW

Q. Please summarize the key drivers of the Company's request in this case.

A. The Company requests jurisdictional rate relief in the amount of $436 million and collection of $24 million associated with the deferred costs related to distribution investments made during the 12 months ended February 28, 2025 ("Distribution Deferral"), which is summarized in Table 1:

Table 1

	(In Millions)
Investment	$172
Investment – Distribution IRM	$22
Operations and Maintenance Expenses	$158
Cost of Capital	$77
Sales/Revenues	$7
Jurisdictional Rate Relief Before Surcharge	**$436**
Distribution Deferral Surcharge	$24
Total Jurisdictional Rate Relief	**$460**

Q. Why has the Company initiated this rate case proceeding?

A. Consumers Energy's commitment to world-class performance delivering hometown service means providing safe, reliable, affordable, and increasingly clean energy to our 1.9 million customers each hour of every day. To deliver on this commitment, the Company has developed compelling testimony in this case, driven by the multi-year investment plan identified in the Company's Reliability Roadmap (historically known as the Electric Distribution Infrastructure Investment Plan or "EDIIP"), to make specific

investments that address asset deterioration and maintain asset health, while also hardening assets against increasingly severe weather. The Company has also devoted considerable effort to developing long-range plans addressing how to transform energy supply to cleaner resources through the Clean Energy Plan put forth in the Company's IRP. Components of the IRP are incorporated into the Company's distribution strategy and vision within the Reliability Roadmap. Together these plans articulate the Company's goals for the future and provide a roadmap for the investments needed to bring this future to fruition.

Q. How has the Company's Reliability Roadmap influenced this filing?

A. As further explained by Company witness Michael P. Kelly, the Company has filed an amended Reliability Roadmap with this case. Starting with the third iteration of the EDIIP, filed on September 27, 2023 in Case No. U-20147, minor revisions were made to reflect the Company's current distribution goals and objectives and the investment plans to meet those objectives and goals. The revisions are primarily centered around updating information to reflect another year of actual historical reliability data, and to extend projected investments by another year into the future. Some content has also been revised to reflect issues highlighted by intervenors in the prior rate case or other regulatory proceedings, specifically the Company's third-party distribution system audit conducted in Case No. U-21305. This Reliability Roadmap maintains planning that includes tools and methods of analysis to better anticipate future challenges. These tools and methods were first introduced in the third iteration of the EDIIP used as the starting point for the Reliability Roadmap filed in this case. This approach underpins the distribution investment request in this case supporting continued investments in infrastructure and spending on line clearing and inspections, while also focusing on resiliency investments. Proposed

distribution spending is designed to meet the collective goal to deliver on the key objectives of the Reliability Roadmap – delivery of safe, reliable and resilient, clean and equitable, and competitive energy to Consumers Energy's customers.

Q. How do the Company's proposals in this case support the Company's Reliability Roadmap and its commitment to improving reliability and resiliency?

A. Consumers Energy has plans necessary for transforming the electric distribution system by investing in core infrastructure assets and modernizing the electric grid to deliver safe, reliable, and affordable electricity to customers. Proposals in this electric rate case support the four key objectives used in building the Reliability Roadmap. Company witnesses Michael P. Kelly, Jennifer M. Partlan, Megan L. Hayward, Scott A. McPhail, Daniel A. Schmoekel, Sara E. Stewart, and Andrew R. Snider provide support for the Distribution investments and Distribution operating and maintenance ("O&M") programs. The Company's proposed electric distribution spending includes capital investments planned for the test year, the 12 months ending April 2027, that total more than $1.5 billion, as well as $301 million for O&M programs. These amounts are comprised of several important programs detailed in this case. The Company has proposed significant O&M funding, more than $186 million, to support the continued increase in the Company's line clearing activities to reduce the frequency of outages and move to a five-year line clearing cycle, as supported by Company witness Stewart. Where outages cannot be completely avoided through capital investment, line clearing, or other O&M, the Company continues to implement measures to decrease the frequency and shorten the duration of outages. Company witness Snider supports the Company's service restoration base O&M funding of $165.2 million based on the historical year cost adjusted for inflation.

Q. What reliability improvements does the Company expect to see from the investments outlined in the Reliability Roadmap as proposed?

A. Reliability improvements provide significant benefits to customers, local communities, and the Michigan economy. The Company's proposed investments in distribution system infrastructure are based on the goal of providing safe and reliable electricity for customers while improving the Company's performance relevant to three reliability metrics — System Average Interruption Frequency Index, Customer Average Interruption Duration Index, and System Average Interruption Duration Index ("SAIDI"). Company witness Kelly presents the Company's modeling projections demonstrating how planned investments are expected to improve reliability across these metrics as identified in the Reliability Roadmap. Based on the modeling results, the Company projects that customers will experience fewer outages on average, and when outages do occur, they will be for shorter periods of time. Projected reliability improvements are based on the Company's planned spending on line clearing, capital investments, and service restoration improvements outlined in the Reliability Roadmap. As explained by Company witness Kelly, these reliability improvements cannot be achieved based on increased line clearing alone. The reliability improvements presented in this case are dependent on necessary and continued investments in the distribution system. Benefits of shifting to a five-year clearing cycle will take time to fully materialize and a line clearing only approach would delay reliability improvements. Capital investments in the distribution system have already begun to deliver reliability benefits and will continue to provide these benefits as the clearing cycle is ramped up. Capital investments in the distribution system should work in

conjunction with increases in forestry work and are necessary to achieve reliability improvements.

Q. Do customers benefit from proactive reliability initiatives?

A. Yes. Vital proactive measures, including tree trimming and vegetation management, can significantly reduce outages and lessen damages from severe weather events. Trees are the greatest cause of interruptions of electric service for customers; mitigating these interruption threats will prevent against interrupted service for customers. As explained in greater detail in the testimony of Company witness Stewart, the Company is proposing a ramp-up to achieving a five-year clearing cycle on the Low Voltage Distribution ("LVD") system. In conjunction with the increase in line clearing, the Company will continue to invest in the distribution system to ensure reliability improvements expected by customers are realized and not delayed.

Q. Please describe the efforts of the Company to minimize customer costs for reliability improvements.

A. The Company has made a proposal in this case that will mitigate the customer impact of the cost of ramping up the line clearing cycle to five years. Company witnesses Patrick D. Daly and Marc R. Bleckman provide testimony explaining the Company's proposed treatment of the expense related to the forestry ramp up. The ramp up of line clearing will occur over a five-year period reaching a steady-state by 2031. The Company is proposing to defer expense to a regulatory asset for amounts above the baseline line clearing expense and securitize the regulatory asset once the balance reaches an appropriate level. Approval of this proposal would allow for a $21.4 million reduction to the filed revenue deficiency

and provide customers the benefit of spreading the recovery of this expense over a longer period at the lower cost of borrowing provided by securitization.

In addition, the Company has and will continue to work diligently to identify opportunities available under the Investment Infrastructure and Jobs Act of 2021 ("IIJA"). Thus far, the Company has been selected for four grants – a $100 million grant for Grid Resilience associated with sectionalization and circuit improvement work in disadvantaged communities; a $500,000 grant to perform pole top rehabilitation and other High Voltage Distribution ("HVD") upgrades; a $4.05 million portion of a Grid Resilience grant to prevent outages and enhance the resilience of the electric grid; and a $19.9 million grant for Grid Resilience and Innovative Partnerships. The final terms of the grants are in the process of being negotiated with the U.S Department of Energy ("DOE"). Company witness Kelly provides more detail on the IIJA grants for which the Company has been selected thus far, associated investments, and efforts taken by the Company to secure IIJA funding for electric distribution investments.

Q. Has the Company proposed measures to further its commitment to the reliability and resiliency of the distribution system?

A. Yes. The Company is making proposals in this case that demonstrate its commitment to the reliability and resiliency of the distribution system. The Company is proposing a shortened line clearing cycle, the scaling of undergrounding, the addition of two programs in the IRM, and a Service Restoration Resiliency Fund and Extraordinary Storm Accounting.

Line Clearing

The Testimony of Company witness Sara E. Stewart provides the Company's vision for the line clearing program. The Company strives for fewer tree-caused outages on its system, improving electric reliability for its customers in all conditions. To achieve this, the Company proposes to maintain a four-year clearing cycle for the HVD system and proposes to ramp-up to a five-year clearing cycle for the LVD system as compared to the Company's previous goal of a seven-year cycle. The ramp up to a five-year cycle will occur through 2031 after which a steady-state cycle maintenance will begin to maintain the five-year cycle. The Company has considered feedback received in the third-party distribution audit report filed by Liberty Consulting Group ("Liberty") on November 15, 2024 in Case No. U-21305 that recommended a four-year clearing for LVD. The Company also has carefully evaluated the costs and benefits of a shorter line clearing cycle and determined that a five-year cycle is the right approach to significantly improve electric reliability. As a result of the additional line clearing work the Company anticipates a 30% reduction in tree caused outage incidents by 2030.

Undergrounding

One key element of increasing system resiliency is undergrounding of distribution lines. As explained by Company witnesses Kelly and Jennifer M. Partlan, the work based on its Commission approved pilot to underground LVD lines was completed in 2024 and early 2025. The results of the pilot show that undergrounding yields similar value to customers when compared to alternatives based on a utility cost test and a better value to customers when the comparison is conducted using the alternate methodology of the societal cost test which includes the customer cost of outages. Based upon the findings of

the pilot, the Company has included 50 miles of undergrounding in the test year. Utilizing learnings from the pilot, the Company understands how to identify where undergrounding work is likely to be lower cost. Based on work conducted by peer utilities, the Company continues to expect an improvement in reliability of 90% or more where undergrounding work is performed.

Wildfire Risk Mitigation

The Company is presenting an updated five-year wildfire risk mitigation plan in response to recent events across the U.S. that highlight the prudency of such planning and investment for this high impact event. As described by Company witness Kelly, the Company is continuing the work approved in Case No. U-21585 including activities related to situational awareness, operational procedures, and vegetation management to address wildfire risks.

IRM

As described later in this testimony, the Company's support and proposed continuation of the Commission-approved IRM reinforces the Company's commitment to distribution system reliability and resiliency. This proposed IRM includes two additional programs critical to customers and reliability. The Repetitive Outages – LVD program addresses issues causing customers to experience four or more outages a year. The Company has not met the Commission's standards in this area and the investment dollars included in the IRM are meant to improve performance in this space. Specifically, the dollars are designed to identify locations on the system where customers experience frequent outages and correct the underlying issues. The other additional program is the Vulnerable Communities Resiliency Plan. This program is crucial for ensuring

disadvantaged communities receive better than average all-weather reliability. The inclusion of these programs in the IRM shows the Company's commitment to ensuring improvement in the number of customers experiencing frequent outages and equitable treatment for vulnerable customers. The IRM discourages the Company from shifting investment dollars away from these critical system investments and provides refunds to customers in the event of underspending.

Service Restoration Resiliency Fund and Extraordinary Storm Accounting ("ESA")

As detailed in the direct testimony of Company witness Snider, the Company is proposing a Service Restoration Resiliency Fund and ESA that ensure every dollar collected from customers for service restoration is used for that purpose or refunded to customers and ensures sustainable service restoration operations during extraordinary storms.

The Service Restoration Resiliency Fund operates as a reserve of surplus service restoration dollars from any prior year that will be used as the first source of funds when actual costs for service restoration exceed base spend levels. This proposed fund will be capped at $30.7 million in the test year, with any dollars exceeding those levels refunded to customers through a bill credit. As described by Company witness Snider, the Company is also committed to continued efforts to create service restoration efficiencies. This fund will ensure that efficiency gains flow back to customers.

The ESA provides for deferred accounting for service restoration costs for significantly severe storms that exceed base spend levels and cause at least 300,000 customer outages over a seven-day period or storms that qualify for a State of Emergency declaration. Storms of this nature are the main cause of increased service restoration

spending and pose the largest risk to sustainable service restoration efforts. There needs to be preparation in the form of the ESA for a future where weather events like the March/April 2025 storms, described by Company witness Snider, are more frequent. The ESA will ensure that service restoration operations during extraordinary events are completed to best serve customers.

Q. How do the proposals in this case support the Company's generation asset strategy and commitment to Michigan's clean energy transformation?

A. The Company's Clean Energy Plan demonstrates that the Company can cost-effectively accelerate its timeline to transition away from coal. Company witnesses Richard T. Blumenstock and Thomas P. Clark offer further details about Consumers Energy's generation asset strategy and projected performance considering the Clean Energy Plan, planned investments in natural gas, battery energy storage systems, and hydroelectric generation. While this case does not request recovery of renewable energy related costs, Company witness Blumenstock does discuss the impact of PA 235 of 2023 ("PA 235") on the future renewable energy portfolio indicating that the Company has filed a Renewable Energy Plan Amendment that provides a plan to comply with the renewable energy standards established in PA 235. The Company's Renewable Energy Plan Amendment shows the Company's commitment to meeting the 50% renewable portfolio standard by 2030 established PA 235. The Company will concentrate investment in new renewable energy resources and continue investment in the existing gas-fired units as this strategy will provide the greatest long-term customer benefit.

Q. Please describe recent events impacting the retirement of the Campbell plant.

A. On May 23, 2025, the U.S. Department of Energy issued Order No. 202-25-3 ("DOE Order") requiring Consumers Energy to continue operating the Campbell plant beyond May 31, 2025. The Company is coordinating with MISO and complying with the DOE Order. The costs presented in this electric rate case have not been adjusted to reflect the impacts of the DOE Order. Consumers Energy plans to request recovery of the costs associated with the DOE Order through a FERC process, as provided by the DOE Order and federal law.

Q. Are hydroelectric investments a component of the Company's electric generation strategy?

A. The Company is evaluating its long-term strategy for the river hydro units. Pursuant to a settlement agreement in the Company's electric depreciation case, Case No. U-20849, and a filing extension approved in Case No. U-21873, Consumers Energy is planning to present a retirement and decommissioning analysis by the end of 2025. The Company will evaluate each facility and determine the best path forward from the perspective of Consumers Energy, its customers, and the state of Michigan. Although this analysis has not been completed, continued investment in safety and reliability upgrades are necessary to operate the river hydro facilities and to comply with applicable law. However, the Company has not included any associated capital spending in this case as a result of a request to continue deferred accounting treatment for any such spending addressed in detail later in this testimony. Company witness Blumenstock explains that a request for proposal ("RFP") was issued in February of 2024 to identify potential buyers for the Company's 13 river hydro facilities. Negotiations related to this RFP are ongoing with an expectation that a

contract with a buyer could be achieved during 2025. If the Company is unable to reach an agreement for the sale of the river hydros or if the Commission does not approve the sale, the Company would revisit the decision to relicense or decommission.

Q. Does the Company's electric rate case application include a proposal related to IT and security?

A. As described in detail by Company witness Stacy H. Baker, the Company is beginning a critical upgrade to its SAP system that has a direct tie to being able to keep Company and customer information safe and secure. Company witness Daly addresses the Company's proposal for recovery related to the SAP S4/HANA project. Mr. Daly makes proposals that would allow for all costs of the project to be collected from customers over the life of the SAP S4/HANA project assets. First, he recommends that O&M expense related to the project be deferred and amortized over the life of the SAP S4/HANA assets explaining that if this proposal is approved the revenue deficiency of the case could be lowered by $14.6 million. Mr. Daly also supports the extension of the amortization period to 15 years for the cloud implementation costs for the SaaS solution creating consistency in the recovery for all aspects of the SAP S4/HANA project.

Environmental Justice

Q. Does the Company's case include Environmental Justice ("EJ") Considerations?

A. Yes. Company witnesses Kelly and Partlan provide discussion on both electric reliability and resiliency in EJ communities, and how these communities are considered in Company investments via Consumers Energy's distribution planning process. Company witness Kelly also describes the Vulnerable Communities Resiliency Plan initiated with a goal of ensuring that no EJ circuits experience worse than industry average reliability. The

Company has also presented results of EJ regression analysis data in the case providing additional transparency around EJ reliability performance. These items included in the case demonstrate the Company's commitment to equity in utility service.

Customer Impacts

Q. Please quantify the overall rate increase if the Commission approves the entirety of the rate relief requested in this case.

A. Consumers Energy's rate request equates to an overall rate increase of 9.2% excluding the distribution deferral surcharge. The requested increase is 9.7% including the distribution deferral surcharge.

Q. What actions has the Company taken to mitigate the customer bill impacts of the investment plans described in this case?

A. Customers' ability to fund the investments in the Company's system is complemented by Consumers Energy's continued focus on cost savings. The Company's continued efforts to improve productivity and reduce costs will allow Consumers Energy to deliver on its necessary investments for customers and keep customer bills affordable.

Q. How will the Company's rate request affect the typical residential customer?

A. The Company expects that with the increase proposed in this case, the typical residential electric customer will pay on average about $4.87 a day for electricity during 2026. In her direct testimony, Company witness Laura M. Connolly explains the rate design details.

The Company understands that this increase will challenge some customers. Recognizing the challenges some customers face, the Company offers a range of assistance options, including the Consumers Affordable Resource for Energy Program, a Residential Income Assistance credit, and a Low-Income Assistance Credit for qualifying customers.

The Company and its employees are also contributors of both time and money to community based groups including the United Way, the Salvation Army, and many other local service organizations.

INTRODUCTION OF WITNESSES

Q. Please identify the other witnesses presenting direct testimony in support of the Company's filing and the topic that each witness will be addressing.

A. The following witnesses will also be providing direct testimony on behalf of Consumers Energy in this filing:

- **Stacy H. Baker** supports the IT Departments, capital expenditures, and O&M expenses that are needed to maintain existing IT systems, enable new security capabilities, and support other technology needs as proposed in the case. Ms. Baker also describes the Company's capital spending and O&M expenses related to cyber security operations and physical security.

- **Marc R. Bleckman** supports the Company's proposed capital structure and cost of capital which should be used in computing the overall rate of return. In addition, Mr. Bleckman provides additional support for short-term debt, projected cash balances, and support for the treatment of the line clearing ramp-up costs.

- **Richard T. Blumenstock** provides an overview of the Company's current generation assets and supports the Company's generation asset strategy including unit retirement dates and plans to maintain safe and environmentally compliant operations of coal plants until retirement, periodic outage plans, generation unit availability, capital expenditures, O&M expenses, employee retention program costs, and a description of environmental regulations for the Company's electric generating fleet. Mr. Blumenstock also describes the evaluation of the long-term strategy for the river hydro facilities.

- **Eugène M.J.A. Breuring** supports the Company's electric revenues, deliveries, generation requirements, and peak demand in the test year.

- **Ann E. Bulkley** supports the Company's proposed Return on Equity that should be used in computing the overall rate of return.

- **Jessica R. Byrom** describes the work performed by the Company's Customer Experience & Operations organization and how this work benefits customers. Ms. Byrom also supports the capital investment and O&M expense associated with executing this work.

- **Thomas P. Clark** provides background, updates, and support for capital expenditures associated with new Battery Energy Storage System projects.

- **Laura M. Connolly** presents the Company's rate design proposals, including an enhancement to its economic development tariff, a coincident peak provision on the General Primary Demand rate, and a change to applying power factor credits and penalties.

- **Amy M. Conrad** describes the Company's overall compensation philosophy and provides support for the recovery of costs related to the Company's annual Employee Incentive Compensation Program ("EICP") at target levels.

- **Patrick D. Daly** presents the historic and test year revenue deficiency, including the treatment of various regulatory assets and liabilities. Mr. Daly also presents the projected test year revenue requirement for Demand Response ("DR") programs and requests related to distribution capital deferrals. In addition, Mr. Daly proposes deferrals related to the line clearing ramp-up and SAP S4/HANA.

- **Emily A. Davis** sponsors the Company's electric cost-of-service study that conforms to methods previously approved by the Commission. She also provides support for calculating the state reliability mechanism charge and substation ownership credit and the DR and IRM surcharges.

- **Matthew J. Foster** supports the Company's Corporate Services O&M expense which includes uncollectible expense, and injuries and damages. Mr. Foster's testimony also supports Corporate Services Capital spending, IT projects supporting Corporate Services, and the request for certain accounting approvals.

- **Alex M. Gast** describes the Company's DR program, associated costs and proposed updates. Mr. Gast also makes a proposal to exclude DR from rate cases going forward and instead have the review of projected DR spending take place in the annual reconciliation case.

- **Brittani A. Gray** presents the Company's proposed tariff language changes to its electric rate schedules.

- **Kendra K. Grob** supports the Company's costs related to retirement, health care, life insurance, long-term disability plans, and other benefits provided to its employees and retirees. Ms. Grob's testimony also supports continuation of the Defined Benefit Pension/Other Post-Employment Benefits Volatility Mechanism.

- **Quentin A. Guinn** describes the function and needs of the Company's facilities and supports proposed capital expenditures and O&M expenses related to the Electric business portion of Facility Operations and Shared Services.

Mr. Guinn also describes the function and needs of the Company's fleet services and supports the fleet investment.

- **Megan L. Hayward** describes and provides the benefits of the Company's HVD lines system, HVD and LVD substations, Metro system, and System Protection assets, and supports the associated capital investments.

- **Michael P. Kelly** provides an overview of the Company's electric distribution strategy and presents an amended Reliability Roadmap using the Reliability Roadmap as filed in Case No. U-20147 as a starting point. Mr. Kelly also explains the Company's distribution strategy and corresponding future investment levels. He outlines the current state and performance of the Company's electric distribution system and how the investments requested in this case will impact reliability. Mr. Kelly also supports the O&M expenses for the electric distribution organization, aside from Line Clearance and Service Restoration.

- **Jon J. Koetje** presents actual 2024 decommissioning and coal ash disposal costs for D.E. Karn ("Karn") Units 1 and 2 and J. H. Campbell ("Campbell") Units 1, 2, and 3 and provides updated projected decommissioning expenses for Karn Units 1 and 2 and Campbell Units 1-3.

- **Scott A. McPhail** provides an overview of the Company's Grid Automation plans and supports the associated capital expenditures.

- **Ashley E. Meschke** supports the Company's requested recovery for EICP employee compensation costs. Ms. Meschke also discusses operational performance goals included in the Company's EICP and how the EICP goals provide benefits to customers.

- **Megan L. Metz** supports PSCR costs expected during the test year and provides the Company's state reliability mechanism capacity charge inputs, cost offsets, demand, and reconciliation. Ms. Metz also provides an update on Midcontinent Independent System Operator, Inc.'s Seasonal Adequacy Construct and supports the value of continued investment in the Company's generation assets and DR programs. Ms. Metz also supports the value of upgrades to the PCI Energy Solutions software.

- **Jeffrey A. Myrom** proposes enhancements to the Transportation Electrification Plan.

- **Jennifer M. Partlan** explains the Company's projected capital costs for the LVD system and the corresponding benefits of these investments.

- **Daniel A. Schmoekel** provides an overview of the Company's streetlighting assets and the strategic plan for management of those assets. Mr. Schmoekel also supports capital expenditures for streetlighting infrastructure. Mr. Schmoekel also discusses the Company's streetlight outage restoration performance.

- **Andrew R. Snider** supports the Company's service restoration spending, including the proposal of a resiliency fund and extraordinary storm accounting, and the capital costs for the Control/Dispatch Center consolidation.

- **Sara E. Stewart** provides an overview of the Company's line clearing program and the Company's proposal to increase spending to ramp up to achieve a five-year effective LVD line clearing cycle while continuing to maintain HVD's four-year line clearing cycle.

- **Caitlin M. Tetrick** supports the operational workforce resources necessary to support the capital investments and O&M spending in LVD and HVD.

- **Brian J. VanBlarcum** supports the Company's property tax rate as well as the excess deferred federal income taxes being returned to electric customers because of the Tax Cuts and Jobs Act of 2017, the Company's Calculation C proceeding.

CASE REQUIREMENTS

Q. Has the Company addressed in this filing the requirements for its next electric rate filing included in the Commission's U-21585 Order?

A. Yes. The following is a list of requirements for Consumers Energy's next electric general rate application included in the U-21585 Order, with the Company witnesses who address the topics:

HVD New Business – The U-21585 Order included a requirement to identify equipment generally needed for distributed energy resource and electric vehicle interconnections, such as transformers, that currently have a long-lead time for procurement and propose a plan for maintaining an adequate inventory of that equipment to support future development. Company witness Kelly addresses this requirement.

LVD Repetitive Outages – The U-21585 Order included a requirement to present a robust case to demonstrate that dollars from the LVD Repetitive Outages subprogram were spent on addressing reliability in LVD repetitive outages. Company witness Partlan addresses this requirement.

AMI Opt-Out Charges – The U-21585 Order included a requirement to reevaluate advanced metering infrastructure opt-out charges to ensure alignment with the cost of service and present the results of this evaluation. Company witness Kelly addresses this requirement.

Hydro Deferral – The U-21585 Order included a requirement that the approved deferral for hydro was subject to review in the next rate case. This requirement is addressed later in my testimony.

Electric Vehicles – The U-21585 Order included a requirement to provide an update on each transportation electrification plan enhancement approved by the Order along with lessons learned. Company witness Myrom addresses this requirement.

Cost Rates – The U-21585 Order included a requirement to (1) explain and justify the size and expense associated with short-term borrowing facilities if only a very small portion is being or has been utilized and (2) provide a more thorough explanation of renewables liability short-term debt process, consistent with the Commission Staff's recommendations in that case. These requirements are addressed by Company witness Bleckman.

Sales Forecast – The U-21585 Order included a requirement to provide both historical and forecasted sales on both a cycle-billed and calendar basis; provide the 60-months of most recent actual historical, weather normalized historical, and projected sales in the same level of granularity. This requirement is addressed by Company witness Breuring.

Forestry – The U-21585 Order included a requirement to provide an analysis of the feasibility of more aggressive line clearing. The Order also required that Consumers Energy incorporate the findings of its Formal Optimization Analysis of Line Clearing Cycles into its forestry line clearing operations and maintenance approach and spending proposal, while also considering the benefits of shifting to a four-year fixed tree trimming cycle. This requirement is addressed by Company witness Stewart.

EICP – The U-21585 Order included a requirement to provide more support and explanation regarding the coordination of operations between gas and electric businesses to justify how the Company can expect electric business employees to achieve the methane emission reduction goals labeled under the "Environmental" category. This requirement is addressed by Company witness Meschke.

Environmental Justice – The U-21585 Order included a requirement to present an EJ Resiliency Plan with specified proposed investments and a regression analysis which includes data on residential disconnections. This requirement is addressed by Company witness Kelly.

State Reliability Mechanism – The U-21585 Order included a requirement to include a reconciliation calculation for the state reliability mechanism. This requirement is addressed by Company witnesses Davis and Metz.

Productivity Offsets to Inflation – The U-21585 Order directed the Company to present more detailed evidence in the next rate case to demonstrate that it is offsetting inflation by productivity gains. Several witnesses address how the Company is using productivity gains to mitigate cost increases. I will also address this requirement later in my testimony.

Customer Outreach – The U-21389 Order included a requirement to continue holding customer outreach events soon after the filing of an electric rate case. This outreach allows an opportunity for customers to provide feedback and provides customers with information on this filed rate case as well as customer assistance information. While not specified in the U-21585 Order, Consumers Energy will continue to hold these customer outreach events. The outreach event for this filing is scheduled for June 26, 2025 from 4 p.m. to 7:30 p.m. at Martin Luther King Jr. Recreation Center, 1107 Adrian Street, Jackson, Michigan 49201.

DISTRIBUTION IRM

Q. Is the Company proposing a Distribution IRM in this case?

A. Yes. The Company proposes to continue the use of the Distribution IRM. The Commission most recently approved a Distribution IRM in Case No. U-21585 covering the 12-month ending February 28, 2026. In this case, the Company is proposing an IRM that will cover a two-year period beginning May 1, 2026, consistent with the start of the test year of this case. Consumers Energy proposes to continue the IRM using the same investment categories approved by the Commission in Case No. U-21585 with the addition of two new sub-programs: Repetitive Outages, and Vulnerable Communities. Company witness Kelly discusses these additional sub-programs in his testimony. Further, the Company proposes that the spending levels included in the IRM for the 12 months ending April 30, 2027 be set at test year levels approved for each program in this case and year 2 of the IRM should be equal to year 1 spending levels.

Q. What level of expenditures has the Company included in the IRM?

A. As further discussed in the testimony of Company witness Kelly, the included expenditure levels are summarized in Table 2 below.

Table 2: IRM Expenditures

Sub-Program/ Investment Category	Proposed IRM Expenditures
Lines Reliability - LVD	$276,191,000
Resiliency – Fractionalization	$11,647,000
System Protection	$4,098,000
Repetitive Outages - LVD	$30,344,000
Vulnerable Communities	$30,000,000
Total	**$352,280,000**

Q. How does the IRM provide customer and stakeholder benefits?

A. The Distribution IRM provides for the recovery of select distribution capital spending programs while allowing for customer protections and additional opportunities for collaboration and review. The proposed IRM includes some of the investment programs that are critical for distribution system reliability. The previously approved IRM programs of Lines Reliability - LVD, Resiliency, and System Protection target improvements critical to reducing major event days. The Repetitive Outage program is specifically designed to identify locations on the system where customers experience frequent outages and correct the underlying issues. The Vulnerable Communities program is crucial for ensuring disadvantaged communities receive better than average all-weather reliability. The IRM process, as discussed below, will provide customer protections and ensure the spending on

these important programs are spent at approved levels to achieve the reliability benefits they support.

Q. Does the Company propose to maintain the same IRM process approved in Case No. U-21585?

A. Yes. The IRM process inclusive of the planning meetings, reporting metrics, and reconciliation process, as approved in Case No. U-21585, should be applied to the requested IRM in this case.

Q. What benefits does the IRM process provide to customers?

A. The IRM and the associated process provides customer protections, transparency, collaboration, and increased accountability for distribution investments. Customers will benefit from the certainty of investments in the capital programs included in the IRM that are critical to improved reliability. In addition, the reconciliation process will ensure customers do not pay to support investments if they are not actually made. The IRM brings additional transparency and accountability to project planning and results through reconciliation filings, collaboration on IRM project planning, and reporting on the execution of those plans. The distribution spending proposed for inclusion in the IRM represents further commitment by the Company to the reliability and resiliency of the electric distribution system as well as a commitment to provide equitable service to customers in our most vulnerable communities. The IRM ensures that approved spending on critical investments is spent on those investments. The reconciliation process for the IRM, by line item, provides a strong incentive for the Company to complete the IRM spending as included in the IRM surcharge and not shift dollars between programs.

Q. Please describe the proposed IRM surcharge for the 12 months ending April 30, 2027 and the 12 months ending April 30, 2028.

A. The calculation of the revenue requirement for the IRM, inclusive of the proposed increase in capital spending, is included in Exhibit A-163 (HJM-1). This annual revenue requirement is then used by Company witness Connolly to provide an allocation of the revenue requirement by rate class and to remove the IRM revenue requirement from the calculation of base rates to calculate the IRM surcharge by rate class for the test-year.

Q. How will base rates be impacted if the Commission adjusts the capital spending included in the IRM?

A. If the Commission adjusts the capital spending included in the IRM, base rates will need to be adjusted and designed to recover the revenue requirement of any capital spending not included in the IRM.

RIVER HYDRO DEFERRAL

Q. Is the future of the River Hydro facilities uncertain?

A. Yes. As discussed by Company witness Blumenstock, the river hydros may be divested, decommissioned, or relicensed for continued operations. The Company is in negotiations for the potential sale of the River Hydro assets. However, if the sale does not materialize or if a sale agreement is not approved by the Commission or Federal Energy Regulatory Commission, the Company would have to revisit the decision to either decommission or relicense for continued operation.

Q. Has the Commission addressed the uncertainty of the River Hydro facilities in a prior rate case?

A. Yes. In Case No. U-21585 the Commission approved the deferral of the revenue requirement of capital spending associated with the river hydros stating:

> "The Commission finds that, due to the uncertainty of the disposition of the 13 river hydros as discussed by the parties, and rather than approve or disallow the capital expenditures that Consumers proposed in this rate case, the company may use deferred accounting of the revenue requirement on actual capitalized investments incurred subject to review in the Company's next rate case."

Q. Given the continued uncertainty of the disposition of the River Hydro facilities, how does the Company propose to treat capital and O&M expense in this case?

A. The Company proposes the continued use of deferred regulatory accounting through the test year of this case for the revenue requirement on actual capital spending incurred related to the River Hydros. As a result, the Company has removed the rate base impact associated with the 2024 historical capital spending and has not included any projected capital spending in the case. O&M expense needed to safely operate the hydro units has been included in the case. If actual O&M expense is lower than amounts included in rates, the Company proposes to defer the difference to a regulatory liability for refund to customers. The proposed treatment of the capital and O&M related to the River Hydros will provide the time needed to understand the future of the River Hydros while ensuring that customers are not asked to pay for investments or operating expenses that are not actually incurred.

PRODUCTIVITY OFFSETS TO INFLATION

Q. The Commission, in its order in Case No. U-21585, directed the Company to present more detailed evidence in the next rate case to demonstrate that it is offsetting inflation by productivity gains. How do you respond?

A. While the Company is committed to transparency and rigor in its economic analyses, it faces significant challenges in isolating and quantifying the precise impact of productivity gains as an offset to inflationary pressures, especially for productivity gains that have not been realized at the time of filing the rate case. Productivity improvements often manifest in indirect or diffuse ways—such as through process efficiencies, technological integration, or workforce optimization—that are not easily captured in traditional financial metrics or short-term reporting frameworks.

It is important to acknowledge that productivity does not always manifest itself as dollar reductions but is often the creation of more efficient outputs or rather the ability to provide more to customers with the same amount of costs. These complexities make it difficult to present granular, standalone evidence that definitively attributes cost containment or margin stability to productivity gains alone. As a result, while the Company can point to broader trends and strategic initiatives aimed at enhancing efficiency, the nature of these improvements does not lend itself to the kind of detailed, itemized documentation required to show productivity gains by line item in witness exhibits. The absence of such detail should not be interpreted as a lack of effort or effectiveness in managing inflationary impacts through productivity.

Further, development of projected costs for many of the programs is more complex than simply applying an inflation factor to historical costs. Each Company witness

supports the costs they are sponsoring in this case and the methodology used to develop those costs. For example, Company witness Stewart describes how the Company uses historical costs plus changes to programs to develop projected test year costs for Line Clearing and includes details of how the costs were projected in her testimony. Ms. Stewart also explains that clearing more frequently reduces unit cost (cost per mile) to maintain the LVD system and that Forestry contains costs through contractually limited inflation increases. Ms. Stewart states that all contractor rates are contractually limited through mid-2029 to an annual adjustment of a minimum of 0.0% per year up to a maximum of 2.5% per year based on the Producers Price Indices WPUFD4 and WPU443.

Company witness Baker describes the method used to project IT Operations O&M, and explains that inflation is not used to project any categorical spend projections for IT Operations O&M expenses, other than labor. She also includes details about key drivers for changes in costs, including resource efficiencies that offset projected labor cost increases, cost optimization efforts in contracts for cloud subscriptions, and license and maintenance agreements and decreases in Non-Labor Other costs based on reductions in business expenses. Ms. Baker also explains that IT does not apply inflation for categorical spend projections for Investments Planning expenses or for IT Investments O&M expenses.

Company witness Byrom explains that Customer Experience & Operations' projected expenses are developed using zero-based budgeting. This means that all expenses must be justified for a new period or year starting from zero, versus starting with the previous budget and adjusting it as needed. She also describes initiatives that have resulted in reduced costs for customers.

Company witness Blumenstock describes how Generation O&M is projected and discusses efficiencies that have limited cost increases in the projected test year.

Company witness Snider explains how the projected test year service restoration costs were developed and discusses the Company's increasing service restoration efficiencies.

Company witness Foster describes how Adjusted Corporate Services O&M expense was calculated and describes a reduction to projected test year O&M due to insurance distributions.

Company witness Guinn describes how the Company projects its facilities maintenance expense and real estate expense and maintains the O&M expense growth at or below the rate of historical plus the current inflation factor year over year.

Q. Please summarize your direct testimony.

A. Consumers Energy respectfully submits this request for $436 million in annual rate relief, and collection of $24 million associated with the deferred costs related to distribution investments made during the 12 months ended February 28, 2025. As explained in this testimony, the requested rate relief can be reduced by $36 million if the proposed deferrals for line clearing ramp up costs and expense related to the SAP S/4/HANA project are approved. Consistent with Consumers Energy's deeply held commitment to provide exceptional value and service to every customer, caring for the communities where we live and work, and delivering on investor expectations, the Company is requesting revenue recovery for infrastructure investments that primarily support the Clean Energy Plan, the Reliability Roadmap, as well as other programs, including the distribution IRM, that will benefit customers. The Company is also continuing its efforts to minimize the increase in

O&M expense through productivity improvements, first time quality, and reducing employee safety incidents. Consumers Energy is committed to customer value and improving customer service and believes that this filing is a representation of the commitment put forth in the Company's purpose – World Class Performance Delivering Hometown Service.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Heidi J. Myers and my business address is One Energy Plaza, Jackson Michigan 49201.

Q. Are you the same Heidi J. Myers who previously submitted direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Association of Businesses Advocating Tariff Equity ("ABATE") witness James R. Dauphinais related to the rate case test year. I will also address Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Nicholas M. Evans' return proposal related to the Investment Recovery Mechanism ("IRM"). In addition, I will also address Attorney General Dana Nessel ("AG") witness Sebastian Coppola's recommendation for the Commission to establish a contested proceeding to review the accounting and costs related to the continued operations of the J.H. Campbell Plant ("Campbell"). I will also address the testimony of Urban Core Collective ("UCC") witness Sergio Cira-Reyes regarding an affordability analysis. Finally, I will address the testimony of Citizens Utility Board of Michigan ("CUB") witness Richard J. Bunch promoting the use of productivity factor adjustments for operating and maintenance ("O&M") and capital expense.

Q. Are you sponsoring any exhibits?

A. No.

Test Year

Q. Has the Commission previously approved Consumers Energy's ability to utilize a Projected Test Year?

A. Yes, the Commission has, for many years, approved the use of projected test years. Most recently in Consumers Energy's gas rate case, Case No. U-21806, the MPSC's September 30, 2025 Order once again approved the use of a projected test year despite being presented with the same arguments from intervening parties that will be addressed in this rebuttal testimony.

Q. What specific guidance did the Commission provide in Case No. U-21806?

A. On page 9 of the Order, the Commission stated that it "finds that MCL 460.6a(1) permits a utility to use projected costs and revenue for a future consecutive 12-month period in developing its request rates and charges. The Commission is not persuaded that Consumers' use of a projected test year in the instant case should be rejected." The Commission noted that "the ALJ's recommendation is consistent with the Commission's enumerated approach and precedent with respect to the projected test year."

Q. What does ABATE witness Dauphinais propose related to the use of a projected test year?

A. On page 12 of his direct testimony, Mr. Dauphinais asserts that the Commission is not required to use a projected test year and suggests that the Commission has opined that if the utility cannot or will not provide sufficient support for a particular revenue or expense item, the Commission may choose an alternative method for determining the projection. He then indicates that the alternative method should be the historical test year adjusted for only known and measurable changes. However, Mr. Dauphinais does not assert that all of

the Company's projected costs were not sufficiently supported nor does he provide an explanation for what he believes constitutes a known and measurable change.

Q. Do you agree with ABATE witness Dauphinais' rationale for moving away from the Commission's approved use of projected test years?

A. No. The following testimony will individually address each of the points made by Mr. Dauphinais.

Q. Please comment on Mr. Dauphinais' assertion on page 10 of his direct testimony that customers experience rate increases sooner using a projected test year than they would under a historical test year.

A. The use of a projected test year provides the calculation of rates necessary during the period for which the rates will be in effect. This is the most accurate way to set rates and, as will be discussed further below, provides Intervenors with an opportunity to comment on the Company's plans for spending prior to the dollars being spent. Not only does Mr. Dauphinais' assertion ignore these points, it identifies a fact, that if acted upon by the Commission, would unfairly remove the fundamental ability of the Company to have an opportunity to earn a fair rate of return on its investments and knowingly provide customer rates that are below the cost to serve them. Mr. Dauphinais' proposal to use a historical test year is based upon the faulty and unreasonable premise that the utility should experience a lag between incurring costs to provide service and the opportunity to recover those costs. The Commission should reject the suggestion to adopt such regulatory lag.

Q. Do you agree with Mr. Dauphinais' assertion on page 10 of his direct testimony that a projected test year eliminates cost containment?

A. I do not. The Company has an incentive to hold spending levels at amounts approved in rates and to spend efficiently. Once rates are established, the Company is left to manage the business within those rates inclusive of risks that are outside the control of the Company such as weather impact on sales. This provides powerful incentive for cost containment.

Q. Do you agree with Mr. Dauphinais' assertion on page 10 of his direct testimony that the use of a projected test year handicaps Staff and Intervenors in reviewing Consumers Energy's rate filings to ensure the projected capital expenditures and expenses are reasonable because they have not yet been incurred?

A. I do not. Providing expected spending for a future test year provides a more transparent rate making process allowing Staff and Intervenors an opportunity to understand how dollars are intended to be spent and opine on the merits of the proposed spending. In comparison, setting rates based on historical spending is inferior as it only allows for review of spending after it has already occurred. This can have unfortunate consequences. If spending is only reviewed after the fact and only then determined to be an item that should be disallowed from rates, it can lead to write-offs for the Company and an inefficient use of a finite amount of dollars available to invest in the system. This is not good for the Company or customers. Customers are better served by the rate setting process provided by projected test years that allows parties to the rate case proceeding an opportunity to understand and opine on the merits of how dollars will be spent in advance of the spending.

Q. On page 9 of Mr. Dauphinais' direct testimony, he has included Table JRD-3 titled Historic Test Year and Projected Test Year Rate Sufficiency/(Deficiency). Do you agree with the conclusions that Mr. Dauphinais reached as a result of the data on this table?

A. I do not. Mr. Dauphinais' assertion based on the table is that the Company "…would not have been able to seek the large rate increases it has sought in its last eight general rate cases, and is seeking in this proceeding, until such time Consumers was actually experiencing the costs it was projecting, but for being permitted to use a projected test year." While it may be true that rate requests would be different if the Company were required to rely on a historical test year for rate relief, it would not remove the need for rate relief but would only unfairly delay it. In fact, the first time rates were established based on a historical test year, it would create a greater deficiency in the next historical year requiring a greater increase in that year. This does not create a regulatory environment conducive to customer interest. Relying on historical test years for setting rates would trade an environment where stakeholders and the Commission have an opportunity to weigh in on spending, projects, and programs before they are implemented for a short-term and inappropriate delay in rate relief. Establishing a built-in regulatory lag as proposed by Mr. Dauphinais would be detrimental to the Company and its customers, and is inconsistent with the Michigan Law providing for rates to be set using projected test years.

Investment Recovery Mechanism Return

Q. What does Staff witness Evans recommend regarding the rate of return for the IRM?

A. On page 11 of his direct testimony, Mr. Evans indicates that the rate of return associated with the IRM surcharge should be lower than the pretax rate of return as ordered in this

case but not lower than the ordered short-term debt rate. He further states that once the investments are found to be prudent and reasonable for inclusion in base rates in a future rate case, the pretax rate of return would apply.

Q. What reason does Mr. Evans give for this recommendation?

A. Beginning on page 12 of his direct testimony, Mr. Evans ties his recommendation for a lower IRM return to his assumption that the Company has under-invested in its distribution system for numerous years. Mr. Evans asserts that the Company has distribution capital projections for the late 2020s that are 4-6 times larger than the spending that occurred in most of the 2010s. He concludes that this points to earlier spending being insufficient and that the higher projected spending is closer in magnitude to what the system requires. He goes on to conclude that this indicates past under-investment in the distribution system.

Q. Please respond.

A. It would not be appropriate to apply a lower return to any portion of distribution capital spending included within the IRM for the reason provided by Mr. Evans.

Q. Why would the application of a lower return as recommended by Mr. Evans not be appropriate?

A. Applying anything less than the pretax rate of return to the IRM investments would be punitive. The cost of the capital investments included in the IRM are collected from customers over time through depreciation expense on those assets. Until the cost of the assets are fully collected from customers, the Company is required to finance the assets. Not allowing the Company to recover the full cost of financing these long-term assets based on reasoning that the Company underinvested in its distribution system in the past is a penalty and inappropriate rate making.

Q. Could this proposal have a negative consequence on customers?

A. Yes. Should a lower return be applied to the investments included in the IRM, the Company would be forced to reevaluate the inclusion of capital dollars in the IRM. The alternative would be to discontinue or reduce the scope of the IRM and include all or most of the projected capital in base rates to avoid being penalized with the lower rate of return. As described in my direct testimony, the IRM provides customer benefits that could be lost if Mr. Evans' recommendation is adopted. The IRM provides an assurance that the distribution capital spending targeted to reliability improvements are spent and provides a process that allows for more stakeholder engagement.

Q. Is Mr. Evans' argument that the Company has underinvested in its distribution system consistent with past Staff positions?

A. No, it is not. Staff did not support the Company's proposed distribution capital investments even when the Company's requested amounts were significantly less than in the last two cases. As shown in Table 1 below, Staff has proposed material distribution capital spending disallowances in prior cases. If you take Case Nos. U-18322 and U-20134 as examples, Staff proposed to disallow over 10% of the Company's ask of $450,305,000 and nearly 15% of the Company's ask of $568,723,000. This is another reason that Staff's proposal to apply a lower rate of return to IRM investments should be called into question. In the same periods where Staff is now saying there was under-investment, Staff proposed to reduce the spending to even lower levels than proposed by the Company.

Table 1: Distribution Capital Spending and Proposed Staff Disallowances

Case Number	Test Year Ending	Company Ask	Staff Proposed Disallowance
U-18322	9/30/18	$450,305,000	10.40%
U-20134	12/31/19	$568,723,000	14.87%
U-20697	12/31/21	$722,675,000	8.66%
U-20963	12/31/22	$766,266,000	4.62%
U-21224	12/31/23	$746,451,000	51.85%
U-21389	2/28/25	$770,680,000	9.33%
U-21585	2/28/26	$1,307,115,000	28.47%
U-21870	4/30/27	$1,529,914,000	6.88%

Q. Is Mr. Evans' suggestion that the Company has underinvested in its distribution system in past years a fair way to evaluate the return to be applied to an IRM in this case?

A. No it is not. Mr. Evans' proposal criticizes the level of the Company's investments made over a decade ago. Using current ratemaking to penalize the Company's investments made a decade prior would be unprecedented. It would be unfair and illogical to punish the Company in a 2026-2027 test year for investments Mr. Evans now says should have been made in the 2010s. Additionally, reducing the return on the investments needed now would not reflect the actual financing costs of the needed investments.

Q. How should the Commission respond to Mr. Evans' recommendation to apply a lower return to IRM investments?

A. The Commission should not adopt this recommendation. The investments included in the IRM should receive the same return applied to all similar long-term capital investments. Anything less than this would be punitive and would create a situation where the Company would not have the opportunity to recover all of its costs of making the needed investments.

Campbell Contested Proceeding

Q. Do you agree with Mr. Coppola's assessment of the Company's position related to the Campbell plant?

A. Yes. As a result of orders[1] the Company has received from the Department of Energy ("DOE"), the Campell Plant has continued to operate past its planned retirement date of May 31, 2025. The most recent order, Order No. 202-25-7, requires the Campell Plant to operate through November 19, 2025. The Company does not propose to adjust amounts included in this case related to the Campbell plant. The Company plans to request recovery of the costs associated with the DOE Orders through a Federal Energy Regulatory Commission ("FERC") process, as provided by the DOE Order, and will refund to MPSC jurisdictional customers any amounts collected through the FERC process that have been collected through MPSC jurisdictional rates. This is consistent with AG witness Coppola's assessment of the Company's position related to the Campbell Plant on pages 77 through 78 of his direct testimony.

[1] DOE Order No. 202-25-3 issued May 23, 2025 and DOE Order No. 202-25-7 issued August 21, 2025.

Q. Does Mr. Coppola agree with the Company's position related to the Campbell Plant?

A. Mr. Coppola agrees, in part, with the Company's position. On page 78 of his direct testimony, Mr. Coppola asserts that the Company's proposed solution to refund amounts collected through the FERC process that have been or will be collected through MPSC jurisdictional rates is the only workable solution at this time.

Q. Does Mr. Coppola make an additional recommendation related to the Campbell Plant?

A. Yes. On page 79 of his direct testimony, Mr. Coppola recommends that the Commission open a new docket for a contested proceeding to review all aspects, impacts, cost and revenue reconciliation, and refunding of net amounts to customers.

Q. Does Mr. Coppola provide a reason for this recommendation?

A. Yes. Mr. Coppola argues it is needed to ensure that a full and proper accounting of costs and revenue from the continued operation of the Campbell plant occurs, as well as the cost recovery in rates established in Case No. U-21585 and the current case.

Q. Do you agree that the Commission should establish a new docket for this purpose?

A. I do not. The establishment of a separate docket for this purpose is unnecessary and premature. The Company can provide for a full review of the costs and revenues related to the Cambell Plant and any associated refund to MPSC jurisdictional customers in the first electric rate case filed after the outcome of the FERC process is known. Any review of this nature should not take place until the outcome of the FERC process is known because it will provide information necessary to inform the analysis. Furthermore, Mr. Coppola has not provided any reason why this review cannot be completed as part of a

future rate case filing. Creating a new docket to review matters related to this issue is unnecessary.

Affordability Analysis

Q. At page 41 of his direct testimony, UCC witness Cira-Reyes suggests that the Commission should require the Company to perform a fulsome official affordability analysis incorporating the Commission's definition of energy affordability to ensure its programs are adequately addressing affordability among its customers before the Commission approves the rate increase. Has it been made clear what should be included in this analysis?

A. No. Mr. Cira-Reyes did not include any additional details regarding his proposed analysis and it is unclear to the Company how this would be done. The referenced Commission's definition of energy affordability is the extent to which a household has the resources to meet their home energy needs for heating, cooling, and other uses in a healthy, sustainable, and energy efficient manner without compromising a household's ability to meet other basic needs. The Company would not be able to incorporate information for all customers for each of the aspects included in the Commission's definition of energy affordability.

Q. Should the Commission, as recommended by Mr. Cira-Reyes, abstain from approving a rate increase in this case until the affordability analysis is completed?

A. No. As indicated, the Company is unsure of how the requested analysis would be completed or if it would even be possible to complete and it is unreasonable to expect that the Company could complete such an analysis in the time between the filing of Mr. Cira-Reyes' testimony and the filing of the Company's rebuttal. As such, the Commission should not wait to approve a rate increase in this case until this affordability

analysis is completed. See the rebuttal testimony of Company witness Jessica R. Byrom for discussion of the Company's customer payment assistance programs.

Productivity Factor

Q. Please summarize CUB witness Bunch's recommendation related to the use of productivity factors in this case.

A. On pages 12 through 35 of his direct testimony, CUB witness Bunch presents his recommendation that the Commission use productivity adjusted inflation to limit growth in O&M expense for all cost categories with the exception of forestry. Mr. Bunch also recommends that the Commission direct the Company to present both O&M and capital test-year cost baseline projections calculated as historical cost adjusted for productivity adjusted inflation in future rate cases with the ability to present other adjustments to the baseline with demonstration of why they are necessary owing to changes in sales, new statutory requirements, or new performance requirements.

Q. Do you agree with Mr. Bunch's recommendation?

A. I do not. The following testimony will address the rationale used by Mr. Bunch in drawing his conclusions and show that the Commission should not adopt his recommendations.

Q. At page 12 of his direct testimony, Mr. Bunch disagrees with the Company's assertion that a comprehensive and transparent method for incorporating productivity gains in its cost and expenditure projections is unnecessary. Please respond.

A. Mr. Bunch mischaracterizes my direct testimony in this case. My direct testimony, at page 29, did not characterize incorporating productivity gains in its cost and expenditure projections as unnecessary, but simply explained the complexities and hindrances of doing so.

Q. On page 19 of his direct testimony, CUB witness Bunch also argues that the Company is inconsistently applying inflation rates to arrive at test year cost projections in this case. Please respond.

A. Mr. Bunch is correct in stating that Company witnesses are not the same in the way they present inflation in their exhibits. However, the projected costs are fully supported by Company witnesses regardless of whether they applied inflation rates to historical costs to develop projected test year costs.

Q. On page 20, Mr. Bunch states the adjustments in Exhibit A-13 (PDD-42), Sch. C-5.1, do not always align with the actual inflation assumptions used by sponsoring witnesses. How do you respond?

A. Exhibit A-13 (PDD-42) is the Company's attempt to show on one page inflation impacts on the projected O&M expenses and is compiled from the detailed exhibits of each witness who sponsors O&M costs. I agree that the inflation data is not presented the same by each witness. However, Mr. Bunch's criticism illustrates that the testimony explains how the costs were developed and proves the point that the costs are fully supported in testimony, regardless of how they were developed.

Q. On page 23 of his direct testimony, Mr. Bunch states that the Company's projected costs are increasing much faster than inflation, and the bulk of the increase in costs is captured in the Other Adjustments columns of the Company's exhibits. How do you respond?

A. Costs above inflation should be included in the Other Adjustments columns; that is exactly what the column is supposed to represent. There are many reasons why costs increase other than inflation and the Company's witnesses fully support their projected costs.

Q. Does Mr. Bunch make a comparison of a regulated utility to unregulated companies for purposes of addressing the issue of inflation?

A. Yes. On pages 13 through 15 of his direct testimony, Mr. Bunch compares a regulated utility to unregulated companies and provides examples of ways unregulated companies can mitigate inflationary cost increases, ultimately concluding that a regulated utility has the same arsenal of managerial responses to inflationary cost increases as companies operating in a competitive market.

Q. What managerial responses to inflation does Mr. Bunch provide?

A. On pages 13 and 14 of his direct testimony, Mr. Bunch indicates a company can extract greater productivity from its existing assets, seek new suppliers or negotiate with existing ones, find an alternative production method, or increase labor productivity.

Q. Do you agree with Mr. Bunch's assessment of a regulated utility's ability to respond to inflationary pressures in these same ways as an unregulated company?

A. I do not. Unlike unregulated companies, a regulated utility has an obligation to serve their customers. Not only do they have an obligation to serve, but there are also expectations attached to safety, service quality, and reliability. For example, Mr. Bunch proposes that a company facing inflation can extract greater productivity from existing assets by running existing machines faster or longer, or it can keep older machines in service longer than it had intended by repairing and servicing them rather than replacing them, or it can run extra shifts to get round-the-clock production. The Company already operates around the clock to meet customer demand and cannot compromise safety or reliability by overextending equipment or deferring necessary investments. Unlike unregulated market participants,

regulated utilities must prioritize long-term system integrity and customer service over short-term cost reductions.

In short, while the Company actively manages costs, its ability to respond to inflationary pressures is constrained by its duty to provide safe, reliable service to all customers at all times.

Q. On page 28 of his direct testimony, Mr. Bunch argues that the Commission should constrain the Company to Productivity-adjusted Inflation ("PAI") increases in O&M and capital expenditures and require it to justify any excursions from these limits ("Other Adjustments") in terms of changes in sales, legal, or performance requirements to force it to become more productive. How do you respond?

A. The Company does not believe Mr. Bunch's PAI methodology should be applied to O&M or capital expenditures. For example, the Company's proposed capital investment in the distribution system enables productivity gains and improved reliability for customers. Aging infrastructure, increasing customer expectations, and evolving reliability standards demand proactive upgrades. These investments are designed to reduce outage frequency and duration, modernize grid operations, and ultimately lower operating expenses over time. For example, automation and grid modernization initiatives reduce manual labor and emergency response costs, directly impacting O&M. These are not short-term gains, but strategic investments that yield long-term value for customers and the system. Therefore, the Commission should not interpret increased capital and O&M spending as a failure to achieve productivity. Rather, it should recognize that these expenditures are foundational to delivering sustained improvements in reliability, safety, and operational efficiency. The Company fully supports its projected costs and the Commission should not apply a blanket

limitation on the Company's expenditures. The test should be whether the individual program expenditures have been supported by the Company as reasonable and prudent.

Q. On page 29 of his direct testimony, Mr. Bunch suggests that the Company should be expected to manage costs the same way an unregulated company would. How do you respond?

A. As a primary matter, Mr. Bunch's implication that the Company does not manage costs is false—as explained by the Company's witnesses in this case, the Company does work to control costs. However, regulated utilities are fundamentally different than unregulated companies and it is not appropriate to expect the Company to be able to mirror how prices may be constrained in unregulated sectors of the economy. While the Company strives to improve its efficiency and productivity in order to control costs, it is important to note that the Company has unique regulatory obligations, most importantly the obligation to serve that may cause it to respond to cost pressures differently than unregulated companies.

Q. Mr. Bunch recommends the Commission apply the PAI factor to all proposed O&M expenses and disallow excess costs unless they are driven by sales growth or specific performance or legal requirements. Would this be an appropriate way for the Commission to determine the appropriate allowable O&M expenses?

A. No. The Company strives to implement and incorporate productivity gains into its costs in order to keep customer rates affordable. The Company also continues to work to improve its processes for identifying and highlighting these productivity gains in its rate cases. However, the standard for cost recovery has been and should be whether the costs are reasonable and prudent, not solely dependent on whether productivity gains have been incorporated into costs or whether costs increase by more than inflation.

Q. How do you respond to the calculation of the proposed O&M disallowance provided on page 34 of Mr. Bunch's direct testimony?

A. Mr. Bunch recommends reducing O&M expense by $51.5 million to adjust all O&M expense, except for forestry, to historical expenses adjusted for productivity adjusted inflation. Mr. Bunch's Table 4 shows $47.7 million, or 93%, of this reduction is related to electric distribution O&M expense. Company witness Michael P. Kelly makes clear that the increase in O&M for this category of expense is directly tied to the Company's Reliability Roadmap. Mr. Kelly notes on page 123 of his direct testimony that "[t]he Company's O&M spending supports its capital investments through maintenance and operations of grid infrastructure, plus engineering and design work required to execute projects, and provides for restoration of service to customers following interruptions." Furthermore, Mr. Kelly detailed that increases in the Non-Forestry Reliability O&M program are driven by expanded inspection and monitoring of system equipment. This includes four sub-programs: Low Voltage Distribution ("LVD") Lines Reliability, High Voltage Distribution ("HVD") Lines Reliability, LVD Substations Reliability, and HVD Substations Reliability. Regarding the LVD Lines Reliability sub-program, Mr. Kelly noted on page 131, lines 3 through 7, of his direct testimony, "[h]istoric spending levels in this sub-program were insufficient to complete all of the IEEE-recommended work. The Company identified this issue when developing the Reliability Roadmap in 2023, and began developing a plan to increase needed maintenance work going forward." Similarly, on page 132, lines 12 through 13, of his direct testimony, Mr. Kelly explained, "[t]he increase in spending is being driven by increased inspections and testing to support projected investment increases in the HVD Lines Reliability capital program." He further

summarized on page 133, lines 4 through 7, of his direct testimony, that "the Company is increasing its total substation O&M spending across the four sub-programs to better align with the Electric Substation Reliability Guidelines ('ESR-1')," and that "[h]istorical levels of funding have not been adequate to complete sufficient inspections or to address maintenance backlogs." Additionally, Mr. Kelly testified on page 141, lines 3 through 5, of his direct testimony, that "the Company is projecting increased spending in these sub-programs to ensure the Company can complete the necessary substation maintenance under the ESR-1 guidelines, as given in the Reliability Roadmap." It is also important to note that increases in the Corrective Maintenance program are not merely inflationary. These increases represent incremental work intended to enhance public safety and support system reliability, which are core objectives of the Reliability Roadmap.

Q. What is the result of Mr. Bunch's proposed disallowance?

A. In order to continue the important distribution reliability work highlighted above, the remaining O&M categories would have to achieve more than a 13% reduction for the test year of this case. This is not a reasonable ask and would most likely leave the Company no choice but to pull back on some of the necessary distribution work.

Q. How should the Commission respond to Mr. Bunch's recommended reduction to O&M expense and his proposal to require the Company to present both capital and O&M expense based on historical amounts adjusted for productivity adjusted inflation in future rate cases?

A. The Commission should not adopt Mr. Bunch's proposed O&M expense disallowance. This testimony describes the numerous issues with Mr. Bunch's proposal. Most importantly, his testimony fails to account for the Company's obligation to provide safe

and reliable service to its customers. There should never be a standard set that simply caps expense levels at amounts below inflation. This would be a major and dangerous deviation from the Commission's review of expense levels through the lens of whether the expenses are reasonable and prudent and in support of safe and reliable delivery of electricity. For the same reason, the Commission should also deny the request to require future rate cases to present both O&M and capital as historical adjusted for a productivity adjusted inflation rate.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Next is company witness, Jeffrey A. Myrom, Mr. Myrom had revised direct testimony consisting of a cover page at 17 pages of questions and answers. We also have rebuttal testimony consisting of a cover page and nine pages of questions and answers in addition to Mr. Myrom's Schedule for Exhibit A-12, Mr. Myrom sponsored Exhibits A-164, A-165, A-223, A-224, and A-230.

THE COURT: Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct and rebuttal -- the direct revised and rebuttal testimony of Jeffrey Myrom is bound into the record and Exhibits A-164, A-165, A-223, A-224, and A-230 are admitted.

(At 3:03 p.m., Exhibits A-164, A-165, A-223, A-224, and A-230 admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REVISED DIRECT TESTIMONY

OF

JEFFREY A. MYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Jeffrey A. Myrom, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Electric Vehicle Customer Programs.

Q. What are your responsibilities as Director of Electric Vehicle Customer Programs?

A. As Director of Transportation Electrification Programs ("TEPs"), I lead the teams for Consumers Energy's PowerMIDrive Residential, PowerMIDrive Public Charging, and PowerMIFleet customer programs.

Q. Please describe your educational background and professional experience.

A. I have a Master of Science Degree in Environmental Policy from Michigan Technological University, and a Bachelor of Chemistry, Environmental Science and General Science from Coe College.

From 2001 to 2006 I served as Deputy Bureau Chief of the Iowa Department of Natural Resources' Energy & Waste Management Bureau ("Bureau"). In that role, I directed all administrative rules processes and amendments for the Bureau. I also represented the Bureau in matters before the Environmental Protection Commission and Iowa Legislature on policy and administrative rules issues.

In 2006, I became employed by MidAmerican Energy, now known as Berkshire Hathaway Energy. In that position, I served as Senior Environmental Policy Analyst, representing MidAmerican Energy on issues related to waste, water, climate, renewable energy, and electric generation resource modeling and planning.

In January 2013, I was employed by Consumers Energy Company as Director of Environmental Regulations, Strategy, and Sustainability. In May 2018, I was promoted to Director of Renewable Energy and Electric Vehicle Customer Products. In this position, I was responsible for administering and expanding the Company's Voluntary Green Pricing programs. Additionally, under my direction, the Company successfully launched the PowerMIDrive pilot in June 2019, approved by the Michigan Public Service Commission ("MPSC" or the "Commission") in Case No. U-20134, and later approved as a permanent residential program in Case No. U-21224. In June 2021, under my direction, the Company also successfully launched the PowerMIFleet pilot that was approved by the Commission in Case No. U-20697, and expanded for fleets serving income qualified communities in Case No. U-20963.

In July 2021, I was promoted to my current position as Director of Electric Vehicle Customer Products. In this position my responsibilities were expanded with the growing pilots, and now include additional team members for the administration of PowerMIFleet, PowerMIDrive Public Charging and PowerMIDrive Residential as permanent programs in the Company's TEP that will benefit all customers.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to propose enhancements to the TEPs that will continue to improve customer experience and benefits without any budgetary increase from prior MPSC approvals. For this testimony, the term electric vehicle ("EV") will be used to collectively describe all forms of EVs, including battery electric vehicles ("BEVs") and plug-in hybrid electric vehicles ("PHEVs").

Q. Have you previously testified before the Commission?

A. Yes, I have previously provided testimony in the Company's 2019 Voluntary Green Pricing application (Case No. U-20649), 2021 Renewable Energy Plan amendment (Case No. U-20984), 2021 General Electric Rate Case (Case No. U-20963), 2022 General Electric Rate Case (Case No. U-21224), 2023 General Electric Rate Case (Case No. U-21389), and 2024 General Electric Rate Case (Case No. U-21585).

Q. Are you sponsoring exhibits in this case?

A. Yes, I am sponsoring three exhibits:

Exhibit A-12 (JAM-1)	Schedule B-5.8	Transportation Electrification Plan Capital Expenditures;
Exhibit A-164 (JAM-2)		Transportation Electrification Plan Deferred Asset Costs; and
Exhibit A-165 (JAM-3)		Transportation Electrification Plan Cost Benefit Analysis.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. Please describe Exhibit A-12 (JAM-1), Schedule B-5.8.

A. Exhibit A-12 (JAM-1), Schedule B-5.8 reflects the capital spend for the historical, bridge, and test years for the TEPs per approvals from prior rate cases. Make-ready capital includes metering and utility-side upgrades such as transformers for new services as previously approved. No additional spend from prior approvals is requested, but the timeline has changed. The Company had anticipated that all remaining capital for the initial fast charging pilot authorization would be complete in 2025; however, factors such as National Electric Vehicle Infrastructure ("NEVI") contracting delays and the Federal

Highway Administration's decision to suspend EV charging infrastructure funding has extended the completion date for multiple projects.

Q. Please describe Exhibit A-164 (JAM-2).

A. Exhibit A-164 (JAM-2) shows spending in this case for TEPs' assets, per approvals from prior rate cases. Again, no additional spend from prior approvals is requested.

Q. Please describe Exhibit A-165 (JAM-3).

A. Exhibit A-165 (JAM-3) summarizes the costs and revenues from optimized EV load growth via the TEPs. The positive NPV clearly shows that the additional load growth from EVs creates margin that exceeds the TEPs revenue requirement and other costs. Thus, the TEPs do not increase rates but instead mitigate rate pressure for all customers.

Q. Please summarize the Company's approved TEP programs and their results.

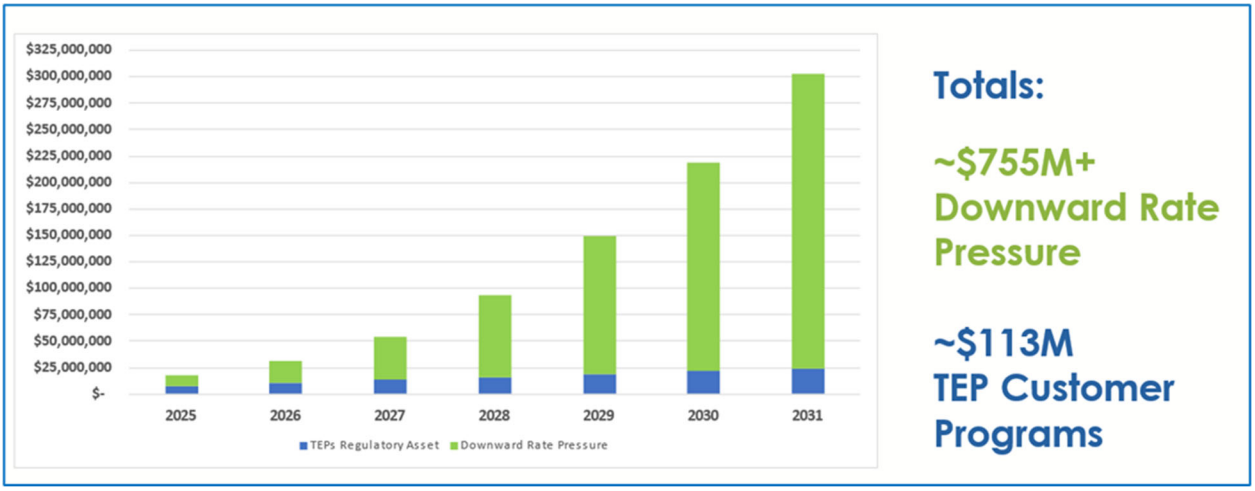
A. Per the Final TEP Order in Case No. U-21492,[1] the Company TEP is centered on long-term strategies to optimize EV charging load to the benefit of all customers, and investments, incentives, programs, and expenditures that are reasonably expected to increase transportation electrification in the Company's electric service territory. The Company's latest TEP is publicly available online[2] and while filed prior to the Final Order via Case No. U-21492, is recognized by the Commission as sufficient for planning purposes until July of 2026, by which time an updated TEP will be filed by the Company.

To accomplish the goals of optimizing load and increasing transportation electrification, the Company continues to support utilizing a portion of the additional

[1] MPSC Case No. U-21492, January 23, 2025 Order, at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000X2NGsAAN (adopting the final Transportation Electrification Plan Filing Requirements as filed by the MPSC Staff on January 24, 2025.

[2] MPSC Case No. U-21538, June 25, 2024 Consumers Energy Transportation Electrification Plan 2024 (2024 TEP Report), at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH.

revenue from EV load growth to pay for TEPs. This is optimal because EV drivers pay for the TEPs and the Company is not raising rates to implement the TEPs. Moreover, while EV drivers fully pay for the TEPs, all customers benefit from the load optimization as the same infrastructure is used to power more EVs, generating additional revenue that mitigates rate pressure. This is clearly shown in the "Cost Benefit Analysis" tab of Exhibit A-165 (JAM-3) and illustrated in the graphic below by comparing the TEPs cost recovery from line 1 in blue, to the total remaining margin after all costs from line 22 in green.



Furthermore, the Company has been highly successful at optimizing EV load growth via its TEP, exceeding the State goal of 80% or more off-peak charging.[3] In fact, in 2023 the Company won the Peak Load Management Alliance Pacesetter award for the best utility EV load management program in the United States, given that residential participants (the largest component of the TEPs) commonly achieves near 95% off-peak charging. Moreover, in early 2025, the Company won the Electric Power Research Institute's ("EPRI's") Technology Transfer Award for applying EPRI and Company

[3] See 2024 TEP Report, page 39, at 0688y00000EFQgtAAH.

research and converting it into load management and EV planning success. The Company's TEP is a national model for EV load management.

To optimize load and increase EV adoption, the Company is focused on three key strategic program areas within the TEP umbrella – Residential, Public and Fleet:

Residential – Being able to reliably and cost-effectively charge at home is critical for most EV drivers, thereby directly impacting EV adoption because if you don't have convenient home charging you are less likely to adopt the technology. Moreover, most homes in Michigan were constructed before EVs became mainstream, meaning that load management is critical given constraints at the panel and potentially the residential distribution system.

The single-family programming implements a combination of educational outreach, Time-of-Use ("TOU") rate, and rebate and incentive programs for off-peak charging at Level 2 ("L2") circuit levels of 50 amps or less (40 amps continuous for 9.6 kW) consistent with residential design standards. The up to $500 rebate (up to $1,000 for income-qualified customers) serves to get EV drivers engaged with their utility and the program, as utility service is not historically part of purchasing a vehicle. From the initial customer contact driven by the rebate offer, EV specialists can educate customers on TOU rates and why off-peak charging is beneficial. Once enrolled, the monthly off-peak charging incentive of $10 (for 12 months) helps reinforce off-peak charging behavior through all four seasons leading to long term off-peak charging behavior.

Furthermore, the residential team is presently implementing a referral incentive program, as the most likely people to purchase an EV are those who know someone with an EV, and thus customers in the program are key components of helping to grow

enrollment via other EV drivers and potential drivers they know. Finally, the team is also presently implementing the dual-cord L2 and splitter incentive,[4] which is designed to prevent EV charging peaks beyond the residential design standards by continuing to utilize a single 50 amp circuit (40 amp continuous) as additional EVs are purchased or leased (a likely occurrence given that most EV drivers remain EV drivers) to spread the load over a longer off-peak time at a maximum 9.6 kW load. Without an incentive for dual-cord L2 or use of a power-sharing splitter, it is more likely that continued EV adoption would result in multiple EV charging circuits in a home, leading to peak loads significantly greater than 9.6 kW and higher ramp rates.

Critically, the Company's residential programming also focuses on multifamily locations, providing equitable charging opportunities at apartments, condos, and townhomes where charging infrastructure is known to be harder to implement. Approximately one in three customers is estimated to live in a multifamily property and with very affordable, used EVs rapidly increasing in market availability, this is an important segment to ensure service for.

In multifamily situations where a customer's residential L2 cannot be directly tied to their meter and parking location, the Company offers up to a $7,500 rebate to add a separate service with at least two plugs powered by 100 amps. The new separate service is usually in a shared parking area, although site hosts can choose if they want to create reserved parking spots and can choose if and how to recoup costs for L2 utilization by residents. The Company also provides signs for display at the charger encouraging

[4] A dual-cord L2 utilizes two plugs that power share from the same L2. A splitter is a device that plugs into a single outlet, and then two separate L2 power share from that device. Both technologies work via a single NEMA 14-50 outlet.

off-peak charging, literature for property managers relaying the same message, and a $20 per month bill credit for 12 months when 80% or more of charging is off-peak. Given tenant turnover challenges, the Company is considering if more active but low-cost controls, such as timers to avoid weekday peak hours, may be useful tools to promote off-peak charging as more load data continues to be gathered.

Public – Public charging advances both grid optimization and EV adoption. Grid optimization is achieved by incentivizing lower-power charging (L2 and L1) at strategic off-peak locations that fit the customer's use case. A few examples of such off-peak use cases supported by the Company TEP include utilizing a L2 community charger on the weekend or overnight if your multifamily property does not offer charging, using a hotel L2 overnight while on business travel or a campground L2 when family vacationing at our excellent state parks on the Lake Michigan Circuit,[5] or using an L1 at the airport or ferry station when away on a multi-day trip.

Such public charging also assists with EV adoption because knowing a charger exists where you want to travel instills charging confidence, and charging confidence is the inverse of range anxiety (which remains one of the top three concerns regarding EV adoption). Moreover, when public charging resources do not exist at such key locations, existing EV drivers are more likely to not take their EV on the longer trip, which reinforces the stereotype that EVs are only for around town and thus not ready for mainstream adoption.

Like the residential multifamily strategy, public L2 and L1 programs utilize educational outreach materials and signage for site hosts, TOU rates, and rebates for

[5] The "Lake Michigan Circuit" is an initiative by Michigan, Wisconsin, Illinois, and Indiana to build EV charging infrastructure along Lake Michigan to support tourism on the coastline.

off-peak charging of up to $7,500 per two L2 plugs or five L1 plugs powered by 100 amps. These power levels serve to spread out the load and optimize off-peak utilization of the distribution system.

Furthermore, community charging also promotes equity. It encourages developers to reach areas that might otherwise lack access to lower-power charging by creating L2 infrastructure within walking distance of multifamily residences.

Fleet – Fleet and workplace charging also directly address grid optimization and EV adoption. For example, workplace charging is not only largely off-peak (typical commutes can finish charging before noon) but also enables EV adoption by customers who may not have access to charging at their home (which is especially challenging for multifamily residents). Moreover, the fleet program presently focuses on outreach, TOU rate, and rebate programs for small and medium businesses, local governments, non-profits, and educational institutions to incentivize off-peak charging. The additional funding for fleets serving income-qualified customers will continue to allow non-profits and local governments to add cost-effective EVs to their fleet that they may not have been able to afford without the funding. Finally, employees who are exposed to the performance benefits of EVs at work are more likely to buy or lease an EV as their next personal vehicle, thereby increasing EV adoption.

The Company's fleet and workplace rebates are up to $7,500 per two plugs powered by 100 amps, with an enhanced rebate of up to $10,000 for workplace L2 that also serve as community charging locations overnight and, on the weekend, (a unique value proposition designed to increase equitable access to charging and maximize use of charging infrastructure). Fleet also offers a long-duration direct current ("DC") rebate of up to

$15,000 per plug of 50 kW or less, focused on medium and heavy-duty vehicles such as electric school buses that have larger batteries and need a higher power level to complete their charging cycle off-peak. Although long-duration DC is at power levels higher than the typical L2, the off-peak load shapes being incentivized mirror those of the other off-peak programs as the duration of charging needed via the DC charger is still four hours or more. Finally, fleets also benefit their entire communities given their high-mileage use and corresponding reductions in local pollution (noise and environmental).

In sum, the residential, public and fleet programs form a TEP portfolio strategy to both (1) optimize the grid to benefit all customers, and (2) aid EV adoption by creating charging confidence via strategically located infrastructure and equitable access to charging. Given the data the Company has reported to the Commission,[6] the TEPs continue to serve the majority of managed charging scenarios, aid with equitable access to charging infrastructure, and achieve the intended results. The Company believes the data strongly supports continuation of the TEP programs.

Q. Are TOU rates enough to optimize off-peak charging without TEP programs?

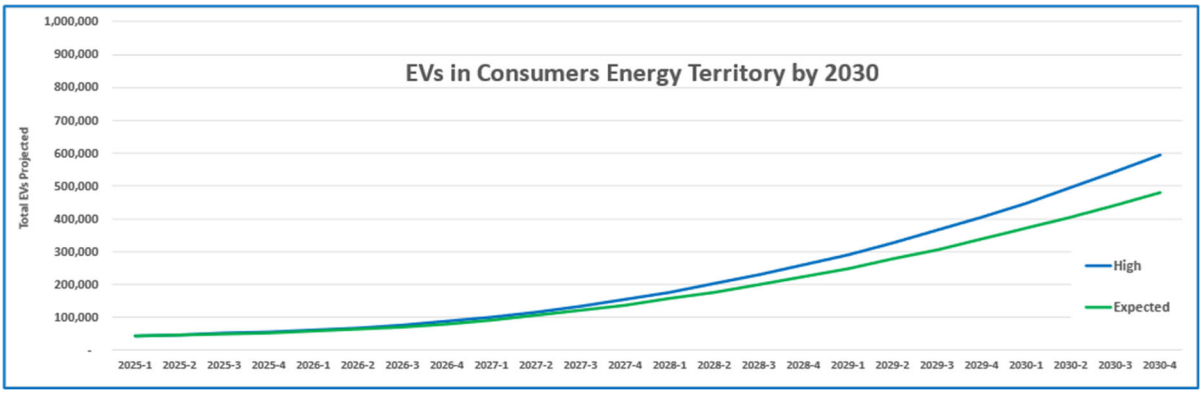
A. Absolutely not. It continues to be the case that a negligible number of EVs enroll in the Company's TOU rate without engagement. For example, in late 2023 the Company's AMI data analysis showed just 493 of the 30,380 EVs enrolled in Rate 1050 (Nighttime Savers) without TEP rebate or incentive engagement, which equates to a mere 1.6% of EV customers. Again, in late 2024, advanced metering infrastructure ("AMI") data analysis

[6] See 2024 TEP Report, at 0688y00000EFQgtAAH; see also 2023 PowerMIDrive and PowerMIFleet Annual Reports, at 0688y000008L9UaAAK and 0688y000008KyQSAA0. The original TEP strategy from 2022 was provided in 0688y000002lGMlAAM. Finally, additional reports from the pilot phases (2022-2020) leading to the TEP are also available at 0688y000003NM62AAG, 068t000000NieAVAAZ, and 068t000000D3t95AAB. All of these regulatory filings show the Company's consistent focus on optimizing the grid and increasing charging infrastructure via strategic locations to benefit customers.

indicated just 526 of 39,950 EVs enrolled in Rate 1050 without TEP program engagement, which is 1.3% of EV customers. The data is incredibly clear and irrefutable. Relying on TOU rates alone is highly ineffectual for EV load management. TEP programming must continue to optimize EV load.

Q. Are EV adoption and load growth projections continuing to materialize similar to the projections provided in prior filings?

A. Yes. EV load growth has been at or above the "500K EV" by 2030 EV scenario utilized in the 2021 Integrated Resource Plan (Case No. U-21090), annual TEP related reports, and prior electric rate cases. While the Company continues to prepare the TEPs to optimize load for one million EVs by 2030 in support of the State's policy goals, which strongly support EV adoption and Michigan's automotive manufacturing economic strength, EVs on the road are trending slightly lower than prior projections. In 2023, an outside source projected there would be 630,000 EVs on the road by 2030, and in 2021, the Company projected there would be 500,000 EVs by 2030.



The latest data from the Michigan Secretary of State also indicates that a range closer to 470,000 to 600,000 EVs by 2030 may be more likely in the Company's territory. Whatever the correct forecast, there are more EVs on the road now than ever before and those EVs

are driving more miles per year. Plus, more EV models are entering the market (SUVs, crossovers, and trucks) that are using more kWh per mile, and the Company's electric territory continues to be a destination for many EVs that reside outside of our electric territory (e.g., the greater Chicago, Detroit, and Toledo metros). Furthermore, our electric territory is the last opportunity to charge before traveling into the Upper Peninsula. Thus, total EV load growth, which is what truly matters for margin analysis and TEP program funding, remains solidly on track as shown in Exhibit A-165 (JAM-3) (see "Cost Benefit Analysis" tab, line 22).

Q. Please describe the specific TEP enhancements proposed to improve customer experience and benefits.

A. To be clear, the Company continues to implement the TEP program enhancements approved in Case No. U-21585, is maintaining the PowerMIDrive Residential program as approved in Case No. U-21224, is maintaining the PowerMIDrive Public Charging and PowerMIFleet programs as approved in Case No. U-21389, and is completing the pilot funds dedicated to customer projects in progress per approvals in Case Nos. U-20134, U-20697, and U-21224. No increases to the TEPs budget previously approved are proposed, and no changes are being made to the core program strategies to optimize off-peak charging from these recent permanent program approvals by the MPSC.

The proposed TEP enhancements are:

(1) The allowance of the weatherized and EV-rated National Electric Manufacturers Association ("NEMA") 14-50 outlets across all L2 rebate categories and NEMA 5-20[7] outlets across all long-duration L1 rebate categories. Given that many new EVs come with, and existing EV drivers utilize, a portable charger, focusing a project on the outlet can simplify installations and reduce costs for host sites. In particular, multifamily locations

[7] NEMA 14-50 and NEMA 5-20 are standardized outlet designs commonly utilized for EV charging. Many L2 utilize a NEMA 14-50 plug for charging up to 9.6 kW, and many L1 utilize a NEMA 5-20 plug for charging up to 1.8 kW.

have expressed interest in bring-your-own-cord ("BYOC") solutions given desires to reduce costs and maintenance. Presently only community charging host sites can utilize outlets as a BYOC option, and the Company believes that it is a useful option across the board to reduce infrastructure costs.

(2) The continuation of Direct Current Fast Charging ("DCFC") rebates on a time-limited and selective basis. The Company continues to believe that DCFC infrastructure incentives are needed to better enable EV travel and to encourage EV adoption. The Company also recognizes feedback from the MPSC Staff that such incentives should work to create a skeleton network, not be a permanent program, and recognize the 30C~~D~~ tax credit impacts.[8] Thus we are modifying our fast-charging rebate proposal as follows:

a. The Company proposes a fast-charging rebate of up to $50,000 per 150 kW DCFC port. The median and average costs of a 150 kW DCFC construction project range between approximately $200,000 and $237,000.[9] The 30C~~D~~ tax credit is available for some, but not all, locations in the Company's electric service territory[10] and may provide a 30% tax credit for the project costs.[11] Thus, it is possible that the cost of a 150 kW DCFC project could be reduced to near $140,000 to $166,000 via the 30C~~D~~ tax credit, and a rebate of up to $50,000 is approximately 1/3rd of the remaining cost, consistent with the original PowerMIDrive pilot approval that collaborated with Charge Up Michigan funds (Charge Up Michigan funds are no longer available, but the 30D tax credit may be available for some locations).

b. The DCFC rebates will only be available for communities that do not have at least four 150 kW DCFC ports across two or more different host sites. The four 150 kW ports per community is proposed as a cutoff because that mirrors the Federal minimum (i.e., skeleton) infrastructure per NEVI Standards and Requirements. See 23 CFR § 680.106(b). However, if those four ports are not spread over two or more different host sites in a community, then competition is limited, and thus an additional site will help keep pricing reasonable. Anecdotally, the Company has noticed that DCFC charging prices come down when a second host-site opens in an area. Thus, these criteria will steer rebate eligibility into communities that do not have fast-charging infrastructure and avoid subsidizing additional builds in urban areas that already have infrastructure.

[8] See MPSC Case No. U-21585, Staff's Reply Brief, pages 26-28, at 068cs00000Rc1jfAAB.
[9] See 2024 TEP Report, pages 28 and 29, Figures 5 and 6, at 0688y00000EFQgtAAH (Median construction costs of $168,654 and make-ready costs of $30,608 total $199,262, while average construction costs of $191,239 and make-ready costs of $45,509 total $236,748).
[10] See the 30C Tax Credit Eligibility Locator for a map of eligible locations. Some areas were only eligible in the past or will drop off in future years.
[11] United States Department of Energy, Alternative Fuels Data Center: Alternative Fuel Infrastructure Tax Credit (last visited April 28, 2025).

c. The DCFC rebate application will only be available for two-years after approval by the Commission. Thus, the fast-charging rebate program proposed is not a permanent offering. However, please note that host sites will be awarded their rebate after construction is complete, which will take longer than the two-year window for rebate applications. Nonetheless, if approved by the Commission, the limited DCFC rebate offering will be contained within the TEP budget already projected and approved, and the Company may close applications if the TEP budget is at risk of being exceeded.

d. The Company will review rebates as they are received, thereby encouraging expedited development of the skeleton network, but retains the right to reject applications that do not offer quality customer experience. Given the competitive nature instilled by the limited TEP budget, and the proposed time and location restrictions for applications, the Company proposes the following criteria to guide DCFC rebate host site selection and aid EV adoption by improving the customer experience:

1. The host site should offer 24-7 charging and amenities, such as restrooms, snacks, and meal opportunities for an average dwell time of approximately 30 minutes. If such amenities are not 24-7, then preference will be given to sites with longer operating hours and a greater number of such amenities at or adjacent to the site. In no case shall sites be allowed that do not offer 24-7 charging or that have no public amenities. Furthermore, chargers and companies that cannot maintain the existing DCFC performance requirement of 97% uptime may also be excluded from future rebates if good faith efforts to restore uptime cannot be demonstrated.

2. The host site should install the fast chargers within view of the road and with pricing signage. Drivers need to see and be able to find fast charging infrastructure. Preference will be given to such sites over those that are at the far edge of a parking lot or hidden to the side or behind a building or other visual obstacle.

3. The host site should utilize fast charging dispensers that can be activated with a credit card or phone tap to pay instead of a specific app. The use of multiple apps can be confusing, is a barrier to adoption, and also slows down throughput at a site if a customer does not already have the app installed and activated. Preference will be given to host sites that replicate the experience of "pay at the pump" that many consumers are used to.

4. The host site must have adequate security lighting and preferably a canopy to protect from the weather. Drivers need to feel safe while charging at night, and fast charging equipment is less likely to be damaged by vandalism or exposure to the elements at such sites. Thus,

preference will be given to host sites that offer good lighting and a canopy.

5. The host site should use traffic flow designs to accommodate the multiple charge port locations of various EV models, larger EVs, and EVs pulling trailers. Preference will be given to sites that utilize pull-through or other layouts that maximize access for different EV types and sizes.

6. More traffic lanes, more ports. While more remote communities on two-lane highways still greatly benefit from the addition of two 150 kW fast charging ports at a host-site, locations near four-lane highways or that experience high seasonal tourist inflows would benefit from more ports. Thus, all host sites must offer at least two 150 kW DCFC ports, and preference will be given to sites with more fast-charging infrastructure, to increase charging confidence by EV drivers. However, no more than four rebates will be offered per host-site in any case.

In sum, the Company believes that the above enhancements will reduce construction costs for the existing L2 and L1 program rebate categories, and temporarily expand rebate offerings to help create a skeleton network of quality fast-charging sites in areas that are still underserved via a time and budget limited competitive process.

Q. Does the continued growth of EV adoption impact the testimony of another Company witness that you wish to support?

A. Yes. While many TEP programs focus on relatively low-power and longer-duration charging to minimize grid impacts, and are successfully optimizing the load from those participants, the Company anticipates that new service requests for DCFCs, both public and for fleets, will grow dramatically in larger population centers. Thus, I support Company witness Jennifer M. Partlan's request to proactively prepare for new and expanded DCFC and larger fleet locations, especially in urban and interstate locations where large developments are already occurring.

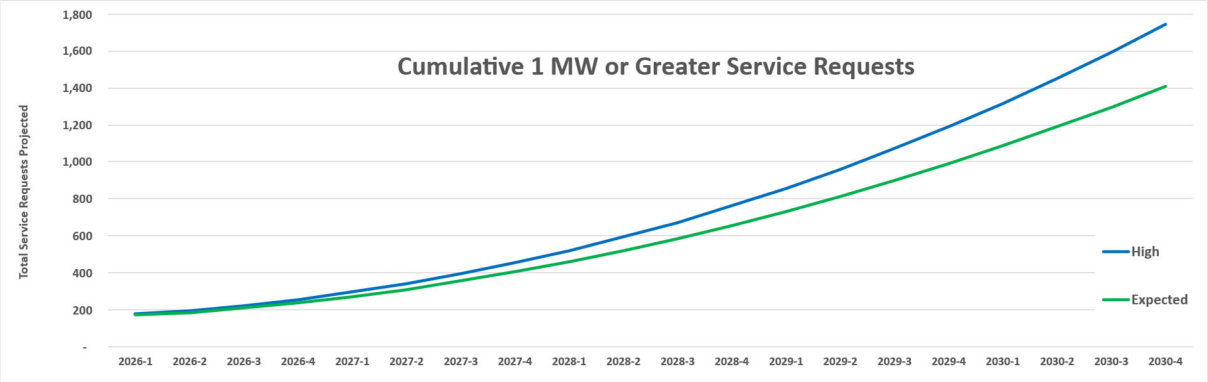
To gain perspective on the magnitude of the challenge, we must first recognize that many utilities are reporting that transformers supporting larger load sites (i.e., 500 kVA and greater) can have lead times of 18 to 24 months or longer. This means that waiting until a request for new or modified service for a fast-charging site or new fleet depot to place an order for these transformers and related equipment will bottleneck EV adoption.

Looking at trends in DCFC development, new or expanded fast charging sites near urban areas are larger and higher power, in addition to being installed at an increasing frequency. For example, market data indicates that one fast charger is constructed for approximately every 85 EVs on the road. Furthermore, developers are considering additional capacity for holidays and cold weather impacts. More fast-charging sites are also being installed with at least four chargers each of 250 kW or higher ratings, and thus potentially drawing up to 1 MW at maximum output. The reason for this is the capabilities of new EVs can often reach higher charging inputs, and customers prefer to choose a fast-charging destination with multiple chargers and higher power outputs to avoid the risk of queuing or impacts from a plug being down for maintenance.

Thus, many urban fast-charging sites are now trending toward sets of 8-12 fast chargers, and we have learned of potential plans for 40 or more chargers along interstate travel corridors. Furthermore, delivery fleets may desire to add hundreds of new EVs per year as their current vehicles age out, and even with L2 charging this can result in large load additions given the scale. These are very important trends to prepare for given continued EV adoption and ensuring Michigan businesses and residents are timely served.

As a planning estimate, utilizing the ratio of one 250 kW fast charger per every 85 EVs, and growth rates trending between 470,000 and 600,000 EVs by 2030, the

Company projects that approximately 1,400 to 1,700 EV service requests of 1 MW or greater could occur by 2030. With the near two-year timeframe to design a new service, procure and install make ready equipment, and energize a site, it is prudent to act now in preparation for forthcoming EV service requests.



Q. In the Company's Case No. U-21585 the Commission ordered the Company to provide updates on approved enhancements and any lessons learned in the Company's next Electric Rate case and PowerMIDrive and PowerMIFleet annual report, as recommended by the Staff. How is this being addressed?

A. The Company ~~will be filing a~~ filed its 2025 TEP Annual Progress report in Docket No. U-~~21389~~ 21538 ~~before July 1~~ on June 27, 2025. ~~The Company incorporates the report by reference~~ I am sponsoring the report as Exhibit A-230 (JAM-6), ~~and I plan to sponsor it as an exhibit through revised direct testimony or rebuttal testimony as appropriate~~ as I indicated I would in my original pre-filed testimony.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

JEFFREY A. MYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Jeffrey A. Myrom, and my business address is One Energy Plaza, Jackson Michigan 49201.

Q. Are you the same Jeffrey A. Myrom who previously submitted direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. All intervenors who testified about the Company's proposed Transportation Electrification Plan ("TEP") enhancements (i.e., Michigan Energy Innovation Business, Institute for Energy Innovation, and Advanced Energy United (collectively referred to as "MEIU"); Michigan Electric Transmission Company ("METC"); Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (collectively referred to as "MNSC"); and Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff")) support the enhancements, albeit some with suggestions for additional enhancements and expenditures. Thus, the purpose of my rebuttal testimony is to address (i) Staff witness Allan D. Freeman's support of the proposal with additional suggestions by Staff witness Kevin Krause; (ii) MEIU witness Sophia Schuster's support of the proposal with suggestions for modification; and (iii) MNSC witness Douglas B. Jester's support of the proposal with suggestions for modification.

Q. Are you sponsoring any new exhibits in this rebuttal testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-223 (JAM-4) Discovery Response 21870-MEIU-CE-0042; and

Exhibit A-224 (JAM-5) Discovery Response 21870-MEIU-CE-0043.

RESPONSE TO STAFF

Q. At page 5, lines 17 through 21, of his direct testimony, Staff witness Freeman recommends that the Company consider impacts of the Electric Vehicle ("EV") tax credit ending to the EV adoption forecast for the upcoming TEP in 2026. How do you respond?

A. I agree. The Federal EV tax credit was intended to incentivize domestic EV and battery manufacturing and, indeed, many such developments are underway or nearing completion that will have a positive impact regarding economies of scale. That said, the price impact of losing the EV tax credit, as of September 30, 2025, in addition to other potential tax impacts from Federal initiatives, like tariffs (which are also intended to promote domestic manufacturing), will take time to develop and recalibrate customer adoption behavior. In the near term, the Company has seen a pull-forward of EV purchases to gain the tax credit before it expires. Consumers Energy anticipates that this pull-forward of purchasing behavior could result in a temporary reduction in EV adoption in Q4 of 2025, but by mid-2026 anticipate a trend toward normalization of customer behavior, barring further regulatory developments. The Company will continue to reforecast EV adoption in the annual reports and TEP filings going forward.

Q. At page 6, lines 3 through 16, of his direct testimony, Staff witness Freeman expresses support for the use of weatherized EV-rated outlets across all rebate categories as proposed. How do you respond?

A. I agree. The upfront cost of installing new charging infrastructure is a significant barrier to multifamily charging, community charging, workplace charging, and for smaller fleets, but presently only community charging has the Bring-Your-Own-Cord ("BYOC") option. The infrastructure cost challenge requires continued focus, especially in lower-income areas and multifamily locations that without financial assistance could not unlock the positive total energy-wallet impacts that transportation electrification can achieve.

Q. At page 7, lines 1 through 12, of his direct testimony, Staff witness Freeman expresses support for a temporary Direct Current Fast Charger ("DCFC") rebate program for underserved communities as proposed. How do you respond?

A. I agree. While the Federal tax credit for EV charging equipment under Section 30C of the Internal Revenue Code ("30C tax credit") is set to expire in June of 2026, which is a new development since the original proposal, the Company believes that the $50,000 rebate proposed is still a meaningful incentive to help create a skeleton network of fast chargers. The Company serves many smaller communities, especially in the northern half of the lower peninsula, that experience seasonal and weekend travel patterns related to Michigan's fantastic tourist destinations, which would benefit from fast charging infrastructure. Moreover, the Company anticipates that EV adoption will continue to expand in all areas of Michigan and the residents near fast charger developments will also benefit.

Q. At page 5, lines 2 through 6, of his direct testimony, Staff witness Krause recommends that Rate GP be closed to new and existing charging stations by June 1, 2028, and that a new Fast Charging Tariff be proposed in the next electric rate case. How do you respond?

A. Additional data and analysis are required. Fast charging infrastructure, especially in more rural areas and locations with seasonal travel, can benefit from rates with reduced demand charge components as Staff witness Krause recommends. However, the PowerMIDrive program is sharing fast charging load profile data with the Company's rates team, and Company witness Laura M. Connolly explains in her rebuttal testimony that this data set is not yet sufficient to propose a new rate structure in the next electric rate case. Additional time for fast charging load profile development is needed before Rate GP can be replaced with one or more alternatives.

RESPONSE TO MEIU

Q. At page 50, lines 12 through 16, of her direct testimony, MEIU witness Schuster recommends that rebate recipients utilizing the proposed outlet option provide proof of EV purchase or lease. What is your response?

A. I agree and disagree in part. A clarification regarding the scope of the BYOC proposal compared to current rebate options may lead us to alignment. In my direct testimony, pages 12–13, I proposed expanding the option to use a National Electrical Manufacturers Association ("NEMA") 14-50 or NEMA 5-20 outlets from community charging applicants to applicants for multifamily charging, workplace charging, and fleet charging. In the community charging scenario, for which BYOC is already approved, no proof of EV purchase or lease is required because the charging infrastructure is open to the public. In a

similar manner, the current Level 2 rebates for multifamily and workplace charging do not require proof of EV ownership or lease because that infrastructure is open to a wide variety of people who will live or work there, be it now or in the future. Thus, the Company is applying a similar logic with the BYOC option, to allow a lower cost solution for the multifamily and workplace host sites to serve their residents and employees, who like the public will change over time and include a wide variety of people. It would be impractical to verify or mandate EV adoption in these circumstances, but we know from the data provided in the Company's annual TEP reports that such charging infrastructure is actively used and largely off-peak. However, fleet charging is a use case where the Company has and will continue to require proof of EV adoption (purchase or lease) to qualify for a rebate, be it a Level 2 plug or a NEMA outlet, because fleet charging is specific to a particular private entity and not for the public at large. Thus, I agree that fleet charging requires proof of EV adoption but disagree that proof is needed for multifamily and workplace charging given the characteristics of those EV charging host sites.

Q. At page 50, lines 19 through 21, of her direct testimony, MEIU witness Schuster recommends that the fast-charging rebate be increased to $70,000 and the two-year application window be extended to six years. How do you respond?

A. If proven necessary with time and market development, such changes can and will be proposed in future rate cases. It is true that changes have occurred since the Company's original proposal that are material to fast-charging market development. For example, the Federal 30C tax credit is set to expire in June of 2026, which makes it nearly impossible that a rebate recipient would qualify for both the proposed rebate and the 30C tax credit. Alternatively, the uncertainty regarding the remaining National Electric Vehicle

Infrastructure ("NEVI") funding is now removed and the State of Michigan has additional flexibility in how it utilizes the NEVI funds. The intent of the Company's proposal is to fill in the final fast-charging infrastructure needs, creating what has been called a skeleton network, upon which the market can expand independent of Company rebates. The Company's long-term TEP strategy remains centered on lower-power, longer-duration, off-peak charging infrastructure to optimize the grid. Nonetheless, if the fast-charging proposal proves insufficient to achieve the skeleton network outcome, then the Company is very willing to consider higher rebate values and a longer application window duration in a future filing.

Q. At page 50, lines 22 through 23, and at page 51, lines 1 through 2, of her direct testimony, MEIU witness Schuster recommends that the Company provide an explicit definition of "community" and a clear rubric for fast-charger rebate applicant review. How do you respond?

A. The Company has provided such a response. Please see the discovery responses to discovery questions submitted by MEIU (21870-MEIU-CE-0042 and U21870-MEIU-CE-0043), included here as A-223 (JAM-4) and A-224 (JAM-5).

RESPONSE TO MNSC

Q. At page 27, lines 7 through 8, of his direct testimony, MNSC witness Jester recommends that the fast-charging rebate application window be extended to seven years given the Federal tax credit recission. How do you respond?

A. As discussed above in response to a similar proposal by MEIU witness Schuster, if proven necessary with time and market development, such changes can and will be proposed in future rate cases. The intent of the Company's proposal is to fill in the final fast-charging

infrastructure needs, creating a skeleton network, upon which the market can expand independent of Company rebates. If the fast-charging proposal proves insufficient to achieve the skeleton network outcome, then the Company is very willing to consider higher rebate values and a longer application window duration in a future filing.

Q. At page 27, lines 9 through 11, of his direct testimony, MNSC witness Jester recommends that the Company allocate specific funding for education and outreach to multifamily dwellings. How do you respond?

A. I agree that market challenges for multifamily charging remain and are significant. To help address this issue the Company has proposed the NEMA outlet alternative, supported by MNSC witness Jester, and continues to promote rebates for community and workplace charging that can also assist multifamily residents as alternative charging locations. Thus, targeted outreach and rebates to address multifamily charging will continue to be a focus in the Company's 2026 TEP. The Company remains open to stakeholder feedback between now and the 2026 TEP filing regarding additional enhancements to address the multifamily challenge, particularly for low-income and moderate-income residents. Given the large proportion of leased EVs, the Company believes that the used EV market will soon allow for even more widespread EV adoption and significant total energy-wallet savings for all customers.

Q. At page 27, lines 12 through 13, of his direct testimony, MNSC witness Jester recommends that the Company propose an active managed charging and telematics pilot in the next rate case. How do you respond?

A. I do not agree at this time, but acknowledge that telematics and active managed charging remain potential future elements of the Company's TEP. While third-party telematics

vendors are piloting with other utilities, the Company wants significant confidence in long-term solutions that have minimal risks and costs, and solutions which cover the majority of EVs in the Company's electric territory. The Enel X situation, for example, left multiple utilities that were dependent or largely dependent upon one company abandoned and starting over with their customer load management program. This is a risk the Company desires to mitigate if moving into a telematics pilot. For reference, Michigan Original Equipment Manufacturers ("OEMs") presently have the majority of EV market share in the Company's electric territory and are actively working on telematics solutions. Furthermore, the longevity of Michigan OEMs provides more confidence than a new company in this space and may be cut out at some point in the future given the proprietary nature of vehicle telematics for OEMs. Thus, the Company is still monitoring market developments regarding telematics and active managed charging, but at this time is unwilling to commit to a pilot in the next rate case.

Q. At page 27, lines 14 through 16, of his direct testimony, MNSC witness Jester recommends that the Company again propose a battery-integrated DCFC pilot in the next rate case. How do you respond?

A. I do not agree that this is necessary, but remain optimistic about battery-integrated fast-charging technology and economics. The Company made a battery-integrated DCFC proposal in the last electric rate case and it was rejected. Instead of reproposing that concept again, the Company utilized the guidance and feedback in Staff testimony and proposed the limited-time DCFC rebate program in the present case. Battery-integrated fast-charging will be eligible for the proposed $50,000 rebate if approved by the Commission.

Q. At page 27, lines 17 through 18, of his direct testimony, MNSC witness Jester recommends that the Company expand PowerMIFleet with a V2G-enabled electric school bus pilot in the next rate case. How do you respond?

A. I do not agree at this time, but acknowledge that bidirectional charging remains a potential future element of the Company's TEP. Several other utilities are already engaged with bidirectional school bus pilots, and the Company will continue to monitor these developments. The Company does not believe that there are unique aspects of bidirectional charging technology specific to its territory that needs to be explored through a pilot at this time.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Thank you, Your Honor.

Next is company witness Jennifer M. Partlin. Ms. Partlin had revised direct testimony consisting of a cover page and a 148 pages of questions and answers. She also had rebuttal testimony consisting of a cover page and 31 pages of questions and answers and Ms. Partlan sponsored Exhibit A-166, A-167, A-168, A-169, revised A-225, A-226, and A-227.

THE COURT: Are there any objections to the admission of this testimony of these exhibits?

Hearing none. The direct revised and rebuttal testimony of Jennifer Partlan is bound into the record and Exhibits A-166 through A-168, A-169 revised, and Exhibits-225 through A-227 are admitted.

(At 3:04 p.m., Exhibits A-166 through A-168, A-169 revised, and Exhibits-225 through A-227 admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REVISED DIRECT TESTIMONY

OF

JENNIFER M. PARTLAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Jennifer M. Partlan, and my business address is 1945 West Parnall Road, Jackson, Michigan, 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently Director of Low Voltage Distribution ("LVD") System Planning.

Q. What are your responsibilities as Director of LVD System Planning?

A. My responsibilities as Director of LVD System Planning include oversight of activities associated with planning for the Company's low voltage electric overhead and underground assets, as well as the Company's streetlight assets.

Q. What is your formal educational experience?

A. I earned a Bachelor of Science degree in Electrical Engineering from Oakland University in 2000. I earned a Master of Science degree in Engineering Management from University of Michigan – Dearborn in 2005.

Q. Please describe your work experience.

A. I began my career with Jacobs Engineering in 2000 as an Instrumentation and Controls Engineer, designing, programming, and commissioning equipment for test cell facilities for automotive companies. In 2008 I started work at General Dynamics in the software lab developing and testing software for military vehicles. In 2010, I worked at General Motors in the transmission testing lab as a test engineer until I started at Consumers Energy in 2011 in the Tools and Work Methods team as the Electrical Team Lead. My duties included working with the team that conducted tool demonstrations, updated work methods

processes, and conducted site visits. From 2013 to 2018 I worked in the Substation Construction department as an Electric Construction Supervisor, working as the project manager for contractors conducting upgrade or modifications to substations or building Consumers Energy substations. I started in the LVD Planning department in 2018 as the Engineering Manager over the Grand Rapids Zone. My team monitored and proposed projects for the LVD lines in relation to capacity, reliability, and managing customer concerns and repetitive outages. In March 2025, I assumed my present position as Director of LVD System Planning.

Q. What is the purpose of your direct testimony in this proceeding?

A. As introduced by Company witness Michael P. Kelly, the purpose of my direct testimony is to explain the Company's projected capital costs in the electric LVD lines system. I will explain the purpose of this spending and the corresponding benefits. The testimony will describe the LVD work and associated costs for the New Business, Demand Failures, Asset Relocations, Reliability, and Capacity programs with a subsection for each LVD lines subprogram.

Q. Please explain the historical, bridge, and test year periods.

A. The historical year is 2024. The bridge period consists of the 16 months ending April 30, 2026. The test year is the 12 months ending April 30, 2027.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-166 (JMP-1)	Bridge Period LVD Project List;
Exhibit A-167 (JMP-2)	Test Year LVD Project List;
Exhibit A-168 (JMP-3)	Conservation Voltage Reduction Measurement and Verification Independent Assessment; and

Exhibit A-169 (JMP-4)	Summary of 2023 and 2024 LVD Repetitive Outages Investment.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes, except that Exhibit A-168 (JMP-3) is an independent assessment prepared by a third party.

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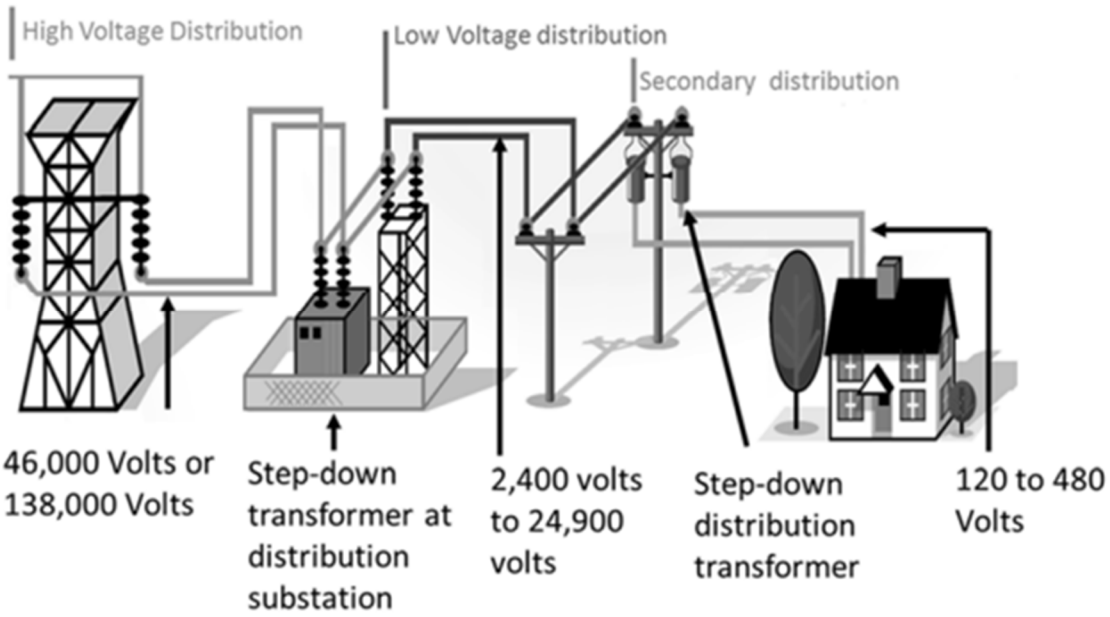
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LVD SYSTEM OVERVIEW

Q. Please provide an overview of the Company's electric distribution system.

A. As discussed by Company witness Kelly, the Company's electric distribution system is comprised of the high voltage distribution ("HVD"), LVD, and Metro systems. The HVD and LVD systems are shown below in Figure 1. My testimony is concerned primarily with LVD lines.

FIGURE 1
HIGH VOLTAGE AND LOW VOLTAGE DISTRIBUTION SYSTEM OVERVIEW



Q. Please provide an overview of the LVD system.

A. The LVD system is comprised of over 111,304 total miles of lines, made up of approximately 51,736 miles of primary overhead, 9,885 miles of primary underground, 31,209 miles of secondary overhead, and 18,474 miles of secondary underground. The LVD system consists of 13 different primary voltages between 2.4 kV and 24.9 kV (grounded-wye and delta). The number and range of primary voltages differ because the Company acquired several distribution systems from smaller distribution companies over

its history. LVD primary voltage is then further stepped down at the distribution pole-top or padmount transformer to a secondary voltage, serving businesses and residences at voltages between 120 Volts and 480 Volts. More than 2,000 LVD circuits serve the Company's approximately 1.9 million electric customers, where a circuit is defined as a combination of electrical devices and hardware that are connected and emanate from an LVD substation to deliver electrical energy to customers, operating at a defined nominal voltage.

Q. What challenges are faced by the LVD system?

A. Broadly speaking, the LVD system is expansive and subject to the greatest threat from common outage causes like vegetation, severe weather, equipment failure, unexpected load increases, and third-party damage. The LVD system is largely a radial system that is not capable of continuing service to customers during outages. Even with advances in distribution automation, the LVD system remains configured such that every outage will interrupt service to a number of customers, though the Company's recent efforts in automation and additional fusing have reduced the number of customers impacted by individual outages.

Q. Does the Company have a strategy for addressing these challenges to the LVD system?

A. Yes. The Company's strategy has been provided in detail in the 2023 Reliability Roadmap, also known as the *Electric Distribution Infrastructure Investment Plan* ("2023 EDIIP"), that was filed in Case No. U-20147 on September 27, 2023, an amended version of which is included in this case as Exhibit A-129 (MPK-19). Company witness Kelly provides direct testimony explaining the Reliability Roadmap. In my direct testimony, I will explain

how the Company is investing in the LVD system to provide needed reliability and resiliency of electric service to customers, and how these investments relate to the plan outlined in the Reliability Roadmap.

LVD PROGRAMS WITH CAPITAL SPENDING

Q. How does the Company classify its LVD capital investments?

A. As discussed by Company witness Kelly, the Company makes capital investments under two broad classifications, *unplanned* and *planned*.

- Unplanned investments include the New Business, Demand Failures, and Asset Relocations programs, and the LVD New Business Capacity subprogram; and
- Planned investments include the Reliability program and the remainder of the Capacity program.

Q. Please summarize the LVD capital expenditure plan in this filing.

A. In this filing, the Company is projecting to spend $1,055,533,000 in capital projects on the LVD system in the bridge period, and $1,086,679 in the test year. Note that the projected investment level for the bridge period is reflective of a 16-month period; on an annualized basis, this would translate to $791,650,000 in annual investment. This investment plan is summarized by the capital programs shown in Figure 2 below.

FIGURE 2
LVD CAPITAL EXPENDITURES BY PROGRAM ($000)

Program	2024 Actuals	Bridge Period	Test Year
New Business	$239,005	$396,010	$337,982
Demand Failures	$199,432	$231,185	$166,120
Asset Relocations	$51,502	$97,911	$79,090
Reliability	$89,384	$248,078	$406,130
Capacity	$45,101	$72,347	$89,110
Electric Other	$7,773	$10,001	$8,248
Total	$632,197	$1,055,533	$1,086,679

Q. How has the level of investment in the LVD system been impacted by the Reliability Roadmap?

A. The Reliability Roadmap did not make a meaningful impact on LVD spending in the New Business, Demand Failures, or Asset Relocations programs. LVD spending in those programs is projected in this case based on relevant data and recent trends as described later in this testimony.

The Reliability Roadmap has led the Company to project increased investment levels in key LVD subprograms in the Reliability and Capacity programs, compared to pre-Reliability Roadmap historical levels. I will address the connection between those LVD subprograms throughout my direct testimony in their respective sections, but I will note here that the largest impacts from the Reliability Roadmap regarding lines are to the LVD Lines Reliability, Resiliency, and LVD Lines Capacity subprograms.

Q. What specific LVD lines projects does the Company expect to invest in during the bridge period and test year?

A. Specific projects are identified in Exhibits A-166 (JMP-1) and A-167 (JMP-2). The exhibits include projects identified with scope, cost, location, benefit type, and benefits. The two quantitative benefit types are:

- Customer outage minutes avoided (also referred to as minute interruptions and abbreviated "CMI"): Product of the number of customers that experience an extended outage of electrical service and the duration of outage measured in minutes.

- Customers impacted: Number of customers served by a project. In the case of commercial customers, the customers impacted are treated as "1."

Note that not all projects have quantitative benefits. Some projects may be completed for regulatory compliance, based on the Company's obligation to serve customers, or other reasons. Company witness Kelly provides more details about how the quantitative benefits

are calculated. Throughout my direct testimony, I will explain more about the specific benefits of each investment sub-program.

New Business Program

Q. What portion of the New Business Program will your testimony discuss?

A. The New Business Program includes the capital costs of connecting new commercial, industrial, and residential customers to the Company's distribution grid. Company witness Kelly introduces and further discusses this program. My testimony will focus on the LVD subprograms:

(i) LVD Lines New Business; and

(ii) LVD Transformers.

Projected spending and benefits are explained in detail in the subprogram section below. LVD Transformers are discussed in a separate section later in my direct testimony.

LVD Lines New Business

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Lines New Business subprogram.

A. The LVD Lines New Business subprogram includes the capital cost of serving new commercial, industrial, and residential customers. These costs include the necessary overhead and/or underground distribution extensions and enhancements required to complete new service connections, including the cost for new plats and developments.

Projects within this subprogram are initiated by customers whom the Company must serve pursuant to tariff requirements. In general, the Company does not have advanced knowledge of LVD Lines New Business projects in the preceding year, as the projects are generally completed within the same year that they are requested. The

projections for installed units and investment are based upon historical activity with adjustments for anticipated variations in business, with input from external data sources, covered in more detail later in my testimony.

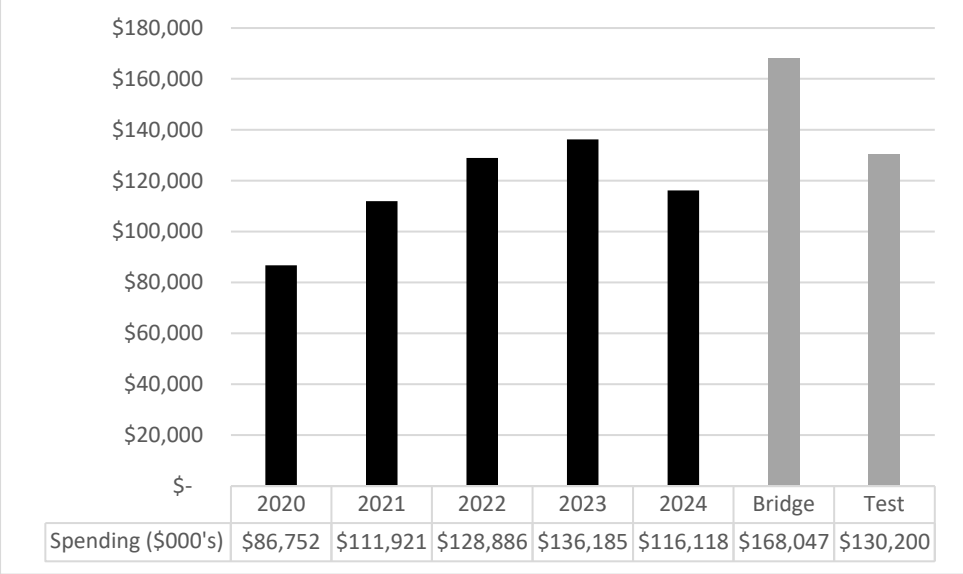
Q. What benefits will customers realize through the Company completing work in the LVD Lines New Business subprogram?

A. Fundamentally, new customers benefit because customers' homes, businesses, and other facilities receive access to the grid and the electricity that it provides. This also supports economic growth in Michigan by enabling new residential, commercial, and industrial facilities to access electricity. The projected spending level will allow the Company to provide a new service installation to every customer who requests it.

Q. What is the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines New Business subprogram?

A. The Company is projecting LVD Lines New Business capital expenditures of $168,047,000 in the bridge period and $130,200,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 1, columns (k) and (l). The Company's historical actual spending in the LVD Lines New Business subprogram, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 1, and below in Figure 3.

FIGURE 3
LVD LINES NEW BUSINESS SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$86,752	$111,921	$128,886	$136,185	$116,118	$168,047	$130,200

Q. How did the Company develop its projected expenditures in this subprogram?

A. Projected expenditures for the LVD Lines New Business Program were based on the expected number of new service connections in the Company's service territory and the projected unit cost of new services.

Q. How does the Company project new service connections?

A. The Company has found that new service connections in its service territory typically track with the number of single-family home permits issued, as reported by the U.S. Census Bureau[1]. Figure 4 below shows the relationship between the two data sets. The Company uses the historical number of new service connections as a foundation for its projections and consults forecasts of single-family housing permits from the Home Builders Association of Michigan ("HBAM") for additional information.

The U.S. Census Bureau data indicates that single family home construction in Michigan increased by 5% in 2024 compared to 2023. The total number of single-family

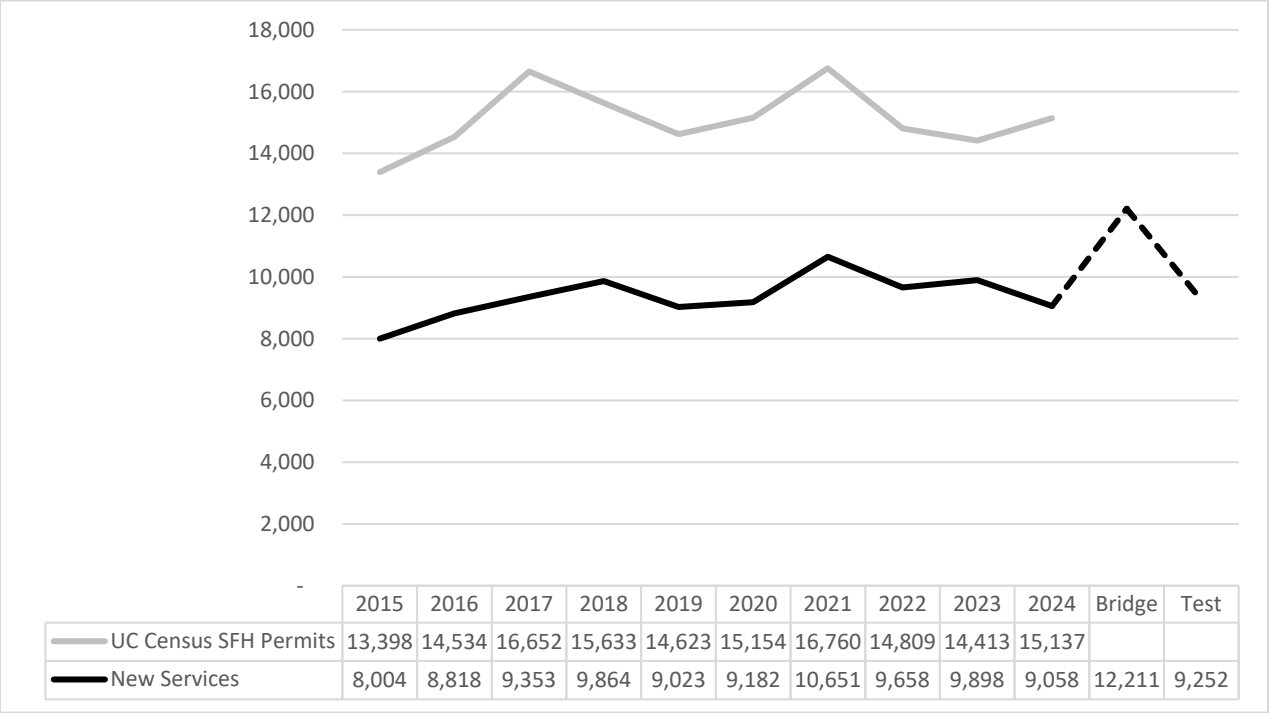
[1] US Census Data: https://www.census.gov/construction/bps/annual.html

housing permits issued in the state last year totaled 15,137 compared to the 14,413 permits that were issued in 2023[2]. In January 2025, HBAM provided a preliminary forecast for 2025 that 15,728 single-family home permits would be issued, a 3.9% increase over 2024.[3] HBAM's forecast supports a growth in Michigan single-family home construction in 2025, and the Company is projecting it will have more new service connections in 2025 and 2026 than in 2024.

Q. What is the Company's forecasted number of new service connections?

A. The Company is projecting 12,211 new service connections for the 16-month bridge period and 9,252 for the test year. Figure 4 below illustrates the historical and projected new service connections.

FIGURE 4
HISTORICAL AND FORECASTED NEW SERVICE CONNECTIONS



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Bridge	Test
UC Census SFH Permits	13,398	14,534	16,652	15,633	14,623	15,154	16,760	14,809	14,413	15,137		
New Services	8,004	8,818	9,353	9,864	9,023	9,182	10,651	9,658	9,898	9,058	12,211	9,252

[2] U.S. Census data: https://www.census.gov/construction/bps/statemonthly.html
[3] HBAM press release: https://hbaofmichigan.com/assets/pdf/Forecast.Release.1.30.25.Final/

Q. Does an average unit cost accurately reflect the expected spend per project for this subprogram?

A. Yes, for the overall subprogram. The unit for this subprogram is projects, and the projects undertaken are specifically tailored to the needs of the customer requesting the work. There is a variance of costs among the different projects; however, because of the volume of service connection units, an average unit cost can be used to develop the spend projections for the overall subprogram.

Q. How does the Company project the average cost of new service connections?

A. The Company used its actual historical costs to inform future unit cost projections for new service connections. While unit cost for this subprogram decreased from 2023 to 2024, the Company anticipates unit cost increases for the bridge period and test year relative to the 2024 amount to account for inflation, increasing length of service lines, and increased amount of underground services. Figure 5 below illustrates the historical and projected unit cost for new service connections.

Q. Is the Company proposing any electric service connection fees related to this sub-program in the instant case?

A. The Company is updating its residential and general service fees. The new fees are addressed by Company witness Brittani A. Gray.

Q. Does the Company expect the proposed changes in fees to affect the number of overhead and underground services installed?

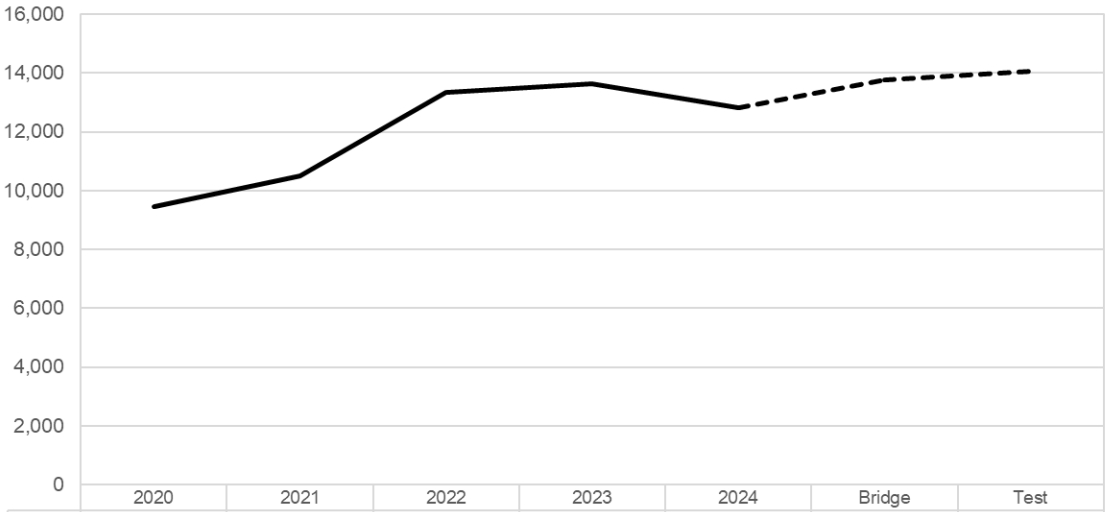
A. Yes. Currently, 87% of the service installations are underground. Given the change in service fees, the Company expects the percentage of underground services to increase to 99%. The 1% of overhead services is expected to remain for customers where an

underground service is not possible due to ground conditions such as wetlands, contaminated soil, etc.

Q. How will customers benefit from underground services?

A. Considering the exposure to weather and trees, storms that pass through the Company's service territory typically affect overhead services much more than underground services. For example, over the last two and a half years, overhead residential services are approximately 45 times more likely to fail than underground residential services. During storm restoration, the Company prioritizes restoration work that restores large numbers of customers or critical facilities, such as hospitals. Given the focus on reducing the time customers spend without power to meet the Commission's Service Quality and Reliability Standards, the restoration of residential services, which typically impacts only one customer, are often not completed until near the end of storm restoration work. With an underground service, customers are less likely to be subjected to a service-driven outage and the long duration of restoration associated with such an outage.

FIGURE 5
HISTORICAL AND FORECASTED UNIT COSTS FOR NEW SERVICE CONNECTIONS



	2020	2021	2022	2023	2024	Bridge	Test
Unit Cost ($)	9,442	10,507	13,340	13,646	12,821	13,762	14,073

Q. Why has the Company experienced increased unit costs in this subprogram in recent years?

A. In addition to inflation, the Company has seen increases in the average length of a new service connection. The Company experienced an increase in unit cost in 2022 due primarily to increased material and contractor costs; however, the Company has worked to reduce its unit cost, resulting in a reduction for 2024.

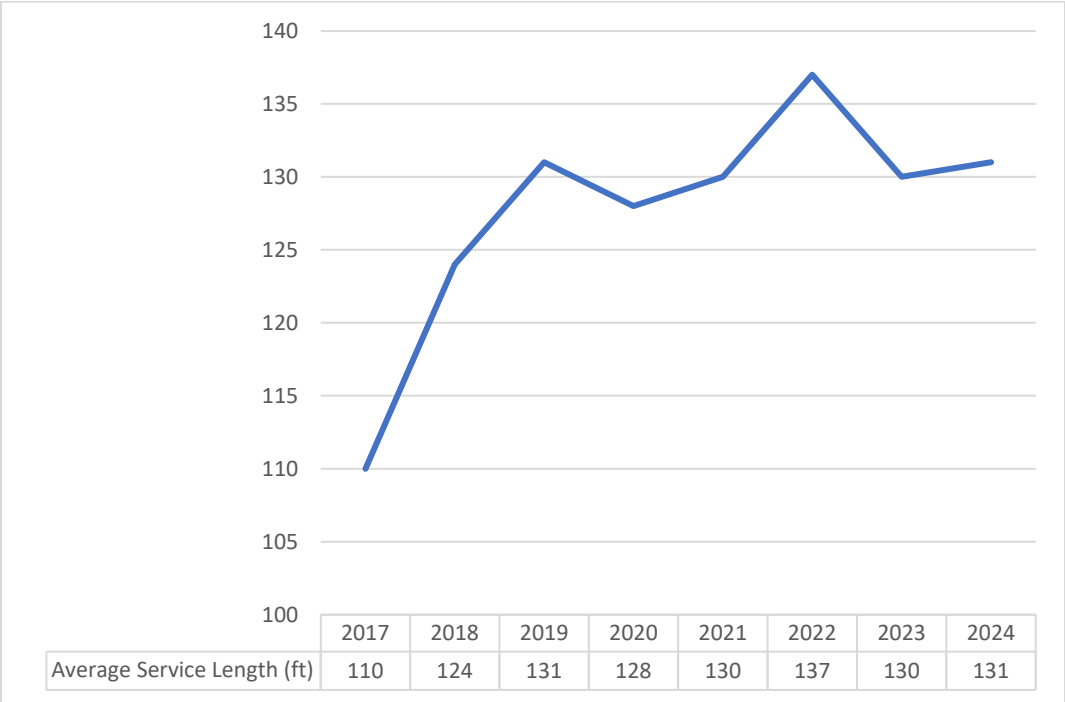
Q. How does the change in the customer service connection fees impact projected spending in this sub-program?

A. The increased fees are expected to save $2 million in the capital requested for service connections. This savings has already been accounted for in the Company's projections, so there is no further new change to the projected spending.

Q. Please describe the increases in average service length.

A. Service length is influenced by the optimal route of the service on a customer's property from the Company facilities to the customer's preferred location. The Company has had an increase in average service from 110 feet in 2017 up to 131 feet in 2024, as shown in Figure 6 below.

FIGURE 6
HISTORICAL AVERAGE SERVICE LENGTH



	2017	2018	2019	2020	2021	2022	2023	2024
Average Service Length (ft)	110	124	131	128	130	137	130	131

Q. Are there unit cost differences between new services installed by contractors and those installed by Company employees?

A. Yes. In its final Order in Case No. U-21585, the Commission directed the Company to develop a comparison and present it in the instant case. The results of this analysis are shown in Figure 7 below.

FIGURE 7
COMPARISON OF COMPANY VS. CONTRACTOR UNIT COSTS FOR LVD LINES NEW BUSINESS, 2020-2024

	2020	2021	2022	2023	2024
Company Units	5,383	5,976	6,601	8,923	8,061
Contractor Units	3,799	4,675	3,057	975	997
Company Unit Cost	$9,314	$9,298	$11,334	$12,002	$11,987
Contractor Unit Cost	$9,449	$11,134	$16,585	$26,383	$21,013

Q. What is shown by this comparison?

A. This comparison illustrates that, beginning in 2021 and especially in 2022, contractor costs have increased more quickly than internal costs, although contractor costs decreased significantly in 2024 following a contract renegotiation. Correspondingly, the Company shifted much of the work in this sub-program to internal resources. However, it is important for the Company to maintain some level of contracted work in this sub-program because contractors provide a level of flexibility and scalability to allow the Company to respond to the unplanned nature of this work. Contractors also ensure that Company employees are able to work on other jobs, such as in the Reliability program.

Demand Failures Program

Q. What portion of the Demand Failures Program will your testimony discuss?

A. The purpose of the Demand Failures Program is to address issues related to customer interruptions and failures of equipment on the distribution system. Company witness Kelly introduces and further discusses this program. My testimony will focus on the LVD subprograms:

(i) LVD Lines Demand Failures; and

(ii) LVD Metering.

Projected spending and benefits are explained in detail in the subprogram section below. LVD Metering is discussed later in a separate section of my testimony.

LVD Lines Demand Failures

Q. Please explain what projects, activities, and other types of work the LVD Lines Demand Failures subprogram expenditures will enable.

A. The LVD Lines Demand Failures subprogram includes capital expenditures incurred during customer interruption restoration, or during the repair or replacement of LVD equipment due to unanticipated failure. The expenditures will enable the Company to respond to day-to-day equipment failures and perform storm restoration work that is capital in nature. Projects are not planned far in advance in this subprogram, because it is meant to quickly respond to equipment failures and customer interruptions that occur in real-time. The LVD Lines Demand Failures subprogram consists of two investment categories: Service Restoration Orders and Security Assessment Inspection Orders.

Q. What work is done in the Service Restoration Orders investment category?

A. Service Restoration Orders consist of work completed on an emergent basis to quickly restore customers who are without power for various reasons, such as following storms or equipment failures.

Q. What work is done in the Security Assessment Inspection Orders investment category?

A. Security Assessment Inspection Orders consist of projects created to fix issues identified in the Company's visual line inspections as discussed further below in my direct testimony on this sub-program.

Q. How does the Company identify and prioritize LVD Lines Demand Failures projects?

A. Once a failure or other damage to the system has been identified, either due to a customer interruption or due to a security assessment, the Company prioritizes its response by

categorizing damage by severity, as either a Priority 1 ("P1") or Priority 2 ("P2"), as shown in Figure 8 below.

FIGURE 8
LVD SECURITY ASSESSMENT HAZARD CODES

Code	Description
P1 - Public Safety	
P1A	Safety Code Violation
P1B	Unusual Public Hazard
P2 - Failures	
P2A	Floating Phase / Neutral
P2B	Broken / Cracked Cross-arm
P2C	Damaged / Cracked Cutout
P2D	Damaged / Cracked Insulators
P2E	Pole: Needing Immediate Replacement
P2F	Pin Pulling from or through Crossarm/Pole
P2G	Other Failed Structure or Equipment

Q. How does the Company respond to P1 and P2 failures?

A. P1 failures include problems that require immediate action to repair the damage. This includes threats to public safety, such as downed wires or exposed underground equipment. P1 failures are addressed within 24 hours.

Like P1 failures, P2 failures consist of equipment that has failed, but P2 failures are less urgent. For example, the Company may find an insulator that has detached from its pin, creating a clearance or public safety hazard. The line would remain energized but no longer in its safe operating condition.

At times, the Company may quickly address a P1 failure by reducing it to a P2 failure. For example, the Company may address exposed cables in a fiberglass pad by applying a temporary patch; the P1 emergency-level issue will have been fixed, but the pad is still failed and requires replacement. Typically, the Company works to respond to P2 failures within 60 calendar days. However, this time can extend beyond 60 days, such as

when the failed equipment has been bypassed and new equipment is on order for replacement.

Q. What approach does the Company use to identify failures on the overhead LVD system?

A. In early 2022, the Company recognized that deterioration was contributing to failures of overhead structures and equipment, increasing System Average Interruption Duration Index ("SAIDI"). Replacement of those failures on an emergent basis cost more than preemptive identification. Accordingly, the Company enhanced its focused assessment program of the LVD overhead system in 2022. The inspections now identify only P1 or P2 failures (note that these are actual failures, in that equipment is already broken, even if customers have not yet been interrupted). This visual line assessment and maintenance approach is supported by Electric Power Research Institute ("EPRI"). Their 2015 technical report, *Distribution Grid Resiliency: Overhead Structures*,[4] page 9-13, states: "Utility field tests showed failures far from tree impacts, particularly at weak equipment. Line inspectors can spot some of these weaknesses, particularly cracks in pole tops and cracked or rotten crossarms. Identifying and fixing these can prevent breakage and reduce overall restoration time." EPRI is describing the items that are contained within the Company's P1 and P2 failure categories.

The assessments completed by the Company also identified opportunities to add high-value lateral fusing, and locations where vegetation was an emergent risk of causing an outage. The lateral fusing additions are discussed in the LVD Lines Reliability section of my testimony. The vegetation threats were addressed by the Line Clearing team.

[4] *Distribution Grid Resiliency: Overhead Structures,* https://www.epri.com/research/products/000000003002006780

Q. Please summarize the recent assessments.

A. The Company completed an assessment of 100% of its LVD overhead system in 2022 and 2023. The P1 and P2 failures identified in these inspections were corrected as part of this subprogram. Based on the findings and benefits of these assessments, the Company began assessing 50% of its overhead LVD system annually starting in 2024.

Q. How many failures were identified through these focused security assessments?

A. In 2022, the Company identified 6,814 P1 and P2 failures. In 2023, 10,738 P1 and P2 failures were identified. In 2024, the Company identified 10,965 P1 and P2 failures. On average the security assessments have identified one failure for every three miles of line.

Q. Are security assessments the only investment needed to improve SAIDI?

A. No. While correcting failures identified during security assessments mitigates customer outages related to deterioration and other defects, this activity alone is insufficient to improve SAIDI overall. Correction of failures does not enhance the overall system. Rather, it simply corrects the defect at a single point on the system. For example, choosing to replace only one tire on a car when it goes flat would result in four disruptions to travel over time, whereas replacing all four tires upon observing the tread on any one tire is worn away would mitigate travel disruptions due to failed tires. Only focusing on security assessments would be analogous to only replacing the single tire that goes flat; making other proactive reliability assessments is analogous to replacing all four tires at once. Therefore, even when security assessment work is completed, the Company still must make investments in other sub-programs to improve SAIDI, particularly in the Reliability sub-programs discussed later in my direct testimony.

Q. What are some examples of failures found in these focused security assessments?

A. The pictures below include examples of P2 failures identified during the assessments in 2024. In the left photo of Figure 9, the lightning arrestor is damaged due to a lightning strike and needs to be replaced. In the right photo of Figure 9, decay and damage at the ground line of a wood pole has greatly undermined the strength of the pole. The left photo of Figure 10 depicts a severely damaged pole, mostly caused by a third party. The right photo of Figure 10 is of a cracked cutout that has fallen off its mount and is being supported by the conductor.

FIGURE 9
LVD P2 FAILURES IDENTIFIED THROUGH SECURITY ASSESSMENTS



FIGURE 10
LVD P2 FAILURES IDENTIFIED THROUGH SECURITY ASSESSMENTS



Q. When the Company determines that service restoration activity is required, what types of projects are considered?

A. The Company performs the following types of service restoration capital work:

- Failed Underground Cable – When a failure occurs on an underground cable, the Company identifies and fixes the fault immediately to restore service to customers. If the underground cable is looped (has feeds from multiple directions), the fault is isolated and service to customers is restored until the permanent restoration is completed within this program;
- Failed Distribution Transformer – These failures are addressed immediately and could warrant further evaluation to determine if the transformer was adequately sized for the load, which, in some cases, leads to replacement of the existing transformer with a larger one;
- Car-Pole Accident – When car-pole accidents result in damage to poles, the Company immediately assigns an available crew to ensure safety of the area, replace the pole, and restring or splice the conductor;
- Broken Cross-arm, Pin/Insulator, or Pole – When poles and other components fail, electric service may be interrupted, or public safety might be affected where the wire is left hanging below the required clearance or out of normal

operating position. The Company will replace any broken equipment (i.e., a cracked cross-arm); and

- Failed Overhead Conductor – When overhead wires fail due to age, deterioration, weather, trees, etc., it typically causes a wire down, which can pose a major public safety hazard. The Company addresses these conditions immediately.

Q. What benefits will customers realize through the Company completing work in the LVD Lines Demand Failures subprogram?

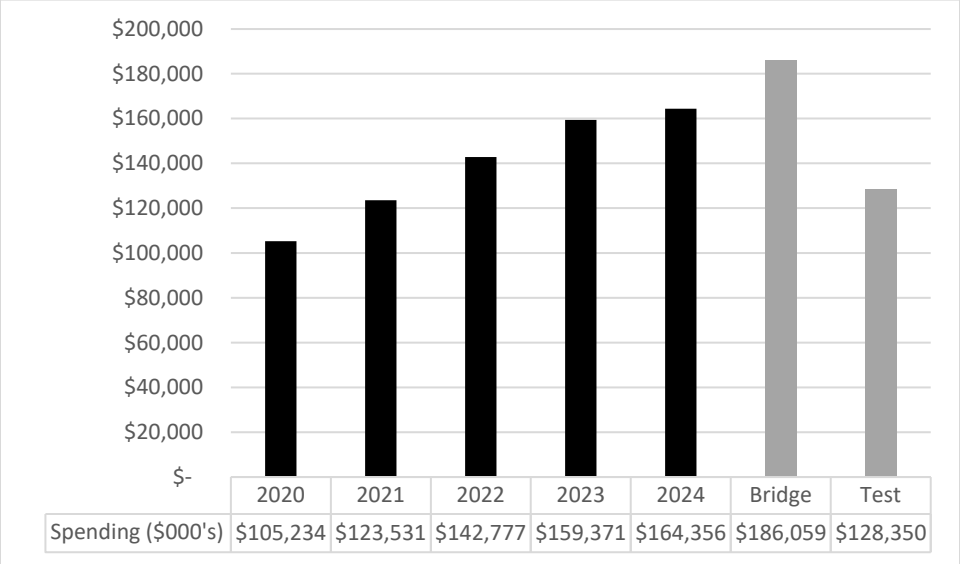
A. This subprogram is essential for the restoration of service to customers for the Company to meet its obligation to serve. Absent investment in this category, customers would remain without electric service because this program funds the basic work necessary to restore electrical service following a failure. Proactive identification of P1 or P2 defects provides a reliability benefit to customers, by improving the condition of system equipment when failed components are replaced, and placing the system back into a normal operating condition, eliminating a likely outage in the future. EPRI also identified this work as a benefit that "…can prevent breakage and reduce overall restoration time." EPRI further noted no drawbacks or risks with this approach. The Company estimates, using its Advanced Distribution Management System ("ADMS") outage data, that the effort in 2022 to identify and remedy P1 and P2 defects reduced system SAIDI, excluding Major Event Days ("MEDs"), by 3.7 minutes through fewer customer outages. In 2023, this effort reduced system SAIDI, excluding MEDs, by 4.0 minutes through fewer customer outages, and in 2024 it was reduced by 6.2 minutes.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines Demand Failures subprogram?

A. The Company is projecting LVD Lines Demand Failures subprogram capital expenditures of $186,059,000 for the bridge period, and $128,350,000 for the test year, as shown in

Exhibit A-113 (MPK-3), line 32, columns (k) and (l). The Company's historical actual spending in the LVD Lines Demand Failures subprogram, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 32, and below in Figure 11. Historical spending from 2020 to 2021 in LVD Lines Demand Failures also included the streetlight failure investment category.

FIGURE 11
LVD LINES DEMAND FAILURES SUBPROGRAM EXPENDITURES



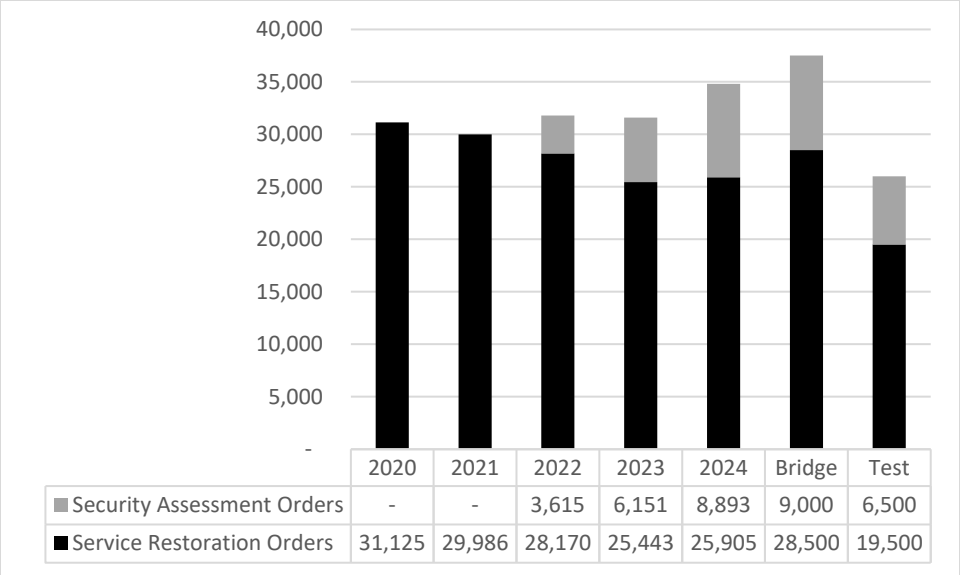
	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$105,234	$123,531	$142,777	$159,371	$164,356	$186,059	$128,350

Q. How did the Company develop its projected expenditures in this subprogram?

A. The Company is projecting it will need to complete 37,500 total orders in the bridge period, consisting of 28,500 Service Restoration orders and 9,000 Security Assessment Inspection orders. Within the test period, the Company is projecting it will need to complete 26,000 total orders, consisting of 19,500 Service Restoration orders and 6,500 Security Assessment Inspection orders. The average unit cost for both periods for Service Restoration and Security Assessment orders is $5,300 and $3,900, respectively. The Company anticipates that its efforts to proactively identify P1 and P2 failures will mitigate the need for a higher number of orders as efforts better match the rate of system

deterioration. The historical and projected number of orders is shown in Figure 12 below. However, the Company's electric distribution system continues to experience weather challenges, which may require an increased number of service restoration orders to be completed.

FIGURE 12
LVD LINES DEMAND FAILURES UNITS



	2020	2021	2022	2023	2024	Bridge	Test
Security Assessment Orders	-	-	3,615	6,151	8,893	9,000	6,500
Service Restoration Orders	31,125	29,986	28,170	25,443	25,905	28,500	19,500

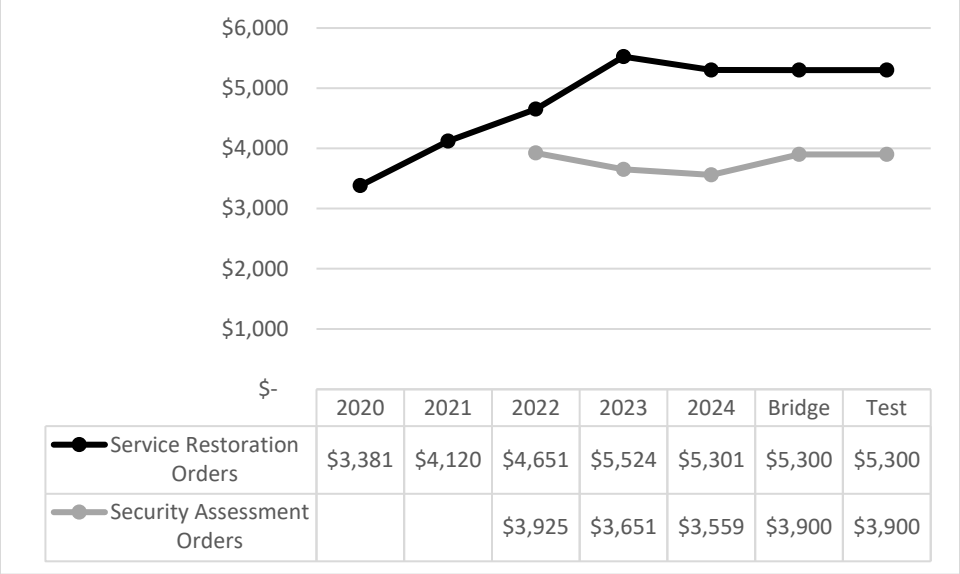
Q. Please explain the year-over-year variation in spending in this subprogram.

A. Spending increases in this subprogram over the past four years have primarily been attributed to unit cost. The four-year average number of orders completed was 31,100.

Q. What are the historical unit costs for the LVD Lines Demand Failures subprogram?

A. The historical and projected unit costs of service restoration orders are provided in Figure 13 below:

FIGURE 13
LVD LINES DEMAND FAILURES UNIT COSTS



	2020	2021	2022	2023	2024	Bridge	Test
Service Restoration Orders	$3,381	$4,120	$4,651	$5,524	$5,301	$5,300	$5,300
Security Assessment Orders			$3,925	$3,651	$3,559	$3,900	$3,900

Q. Please explain any variation in unit costs over time.

A. Service restoration costs can vary due to variations in size and complexity of work orders. The increase in failure unit costs can be attributed to increased material costs as noted in the LVD Lines New Business section of my testimony. The costs of wire, cable, and poles have increased in the last three years. Additionally, the Company's proactive approach to address failures has increased the amount of materials used, and thus time spent, on each of those repairs. For Service Restoration Orders, the Company is projecting the same unit costs for this case ($5,300 per order) that were used to project the costs approved by the Commission in Case No. U-21585.

Q. Does an average unit cost accurately reflect the expected spend per project for this subprogram?

A. Yes. Unit costs can provide a generally reasonable expectation of the overall average project cost within the LVD Lines Demand Failures subprogram. However, any individual

project in this subprogram can range from a few hundred dollars to replace pins and insulators to as high as $500,000 to replace failed underground cable and equipment.

Asset Relocations Program

Q. What portion of the Asset Relocations Program will your testimony discuss?

A. The Asset Relocations Program includes capital investments to relocate electric assets to accommodate road, building, and other third-party construction projects, as well as internal Company projects. Company witness Kelly introduces and further discusses this program. My testimony will focus on the LVD Asset Relocations subprogram. Projected spending and benefits are explained in detail in the subprogram section below.

LVD Asset Relocations

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Asset Relocations subprogram.

A. The LVD Asset Relocations subprogram responds to internal and external requests to relocate LVD lines. This subprogram also includes "make-ready" work to prepare LVD poles for third-party attachments; make-ready work can include physical relocation of a pole, but it may also include work to strengthen a pole to allow it to support additional weight. State and municipal agencies, private property owners, and other Consumers Energy departments make requests for relocations; in addition, telecommunications companies request make-ready work so they can attach phone and cable lines and cellular equipment on poles. The subprogram includes any reimbursements from the requesting party, which directly offset expenses incurred to perform the work. The annual subprogram expenditures are based on the cost to relocate less the reimbursements received. Due to the demand-based nature of this subprogram, the Company does not follow a specific

planning cycle, and generally cannot plan relocation projects far in advance. Each request contains different timelines and requirements based on the nature of the request, and the Company constantly adjusts timing of projects to meet customer schedules. The Company projects its spending levels based on historical activity, while also accounting for observed trends, particularly related to economic activity.

Q. When does the Company request reimbursement for a third-party initiated relocation request?

A. The Company seeks reimbursement for a third-party initiated relocation request anytime a requesting party requests relocation of Company facilities where the Company has existing, valid rights for the location of its facilities.

Q. Does reimbursement match the cost of relocation?

A. Reimbursement does not always match 100% with the cost of the relocation because the reimbursement request is based on a design estimate. The actual construction costs may come in higher than the design estimate due to unforeseen operational expenditures, such as changes to field conditions, safety mitigation (i.e., traffic control), or other factors. In addition, there may be times where it is in the customers' best interest to perform some additional rehabilitation work to adjacent structures or equipment that would not be billed to the requesting party.

Q. How does the Company use information provided by a party requesting relocation?

A. The Company studies the descriptions, maps, surveys, designs, and other documentation provided by the requester, and combines that documentation with internal maps and field measurements to determine what Company facilities, if any, require relocation and where assets should be relocated.

Q. What actions does the Company take when relocation is required?

A. For requests requiring significant relocation or changes to the LVD system, the Company evaluates the proposed changes against a load flow analysis and reliability assessment to determine if relocation will have an adverse effect on the system. If a proposed relocation will negatively impact the reliability or capacity of the LVD system, changes would be necessary. For example, a customer could request relocation of facilities to the edge of their property line, but that move could put the facilities in dense vegetation, making the line less accessible and requiring more line clearing. In that case, the Company would work with the customer to find a better route that meets the customer's needs without impeding reliability. On the other hand, if the relocation significantly changes the length of conductor, it may create a capacity issue and the conductor would need to be upgraded in size.

Q. Please describe the types of projects that the Company includes in the LVD Lines Relocation subprogram.

A. The Company categorizes requests for relocation as:

(i) customer requested (government agencies or private property owners) and requested by other departments within Consumers Energy;

(ii) relocation of LVD underbuild on HVD poles; or

(iii) attachment parties requesting make-ready work.

Q. What is the nature of relocation requests made by government agencies?

A. Government agency requested LVD relocations can fluctuate for many types of projects, such as road and bridge widening or improvements, repairs to municipal facilities, and streetlight and traffic signal modifications. Road and bridge widening, or improvement projects, require the Company to move poles, wires, and other LVD equipment due to

changes to the road location and grade, and to provide proper clearance for any large equipment that the road construction contractors have on site. Large additions to civic buildings can also lead to local governments asking the Company to relocate LVD assets to accommodate those projects. Government agency timelines can vary widely based on size and complexity.

Q. What is the nature of relocation projects requested by private property owners?

A. Private property owner requests vary widely based on the type of project and project timeline. Property owners request LVD relocations for building additions, logistics, landscaping, or other construction projects. Private landowners often request relocation of overhead lines out to the road or underground, particularly to facilitate moving large farm equipment. Residential customers often request relocation of LVD lines to facilitate building an addition, pool, shed, barn or landscaping feature, such as a pond or berm. Commercial customers often request relocation of poles from a parking lot or other area.

Q. What is the nature of relocation requests generated within the Company?

A. Relocation requests within the Company may come from the HVD Planning group, the Substation Planning group, or the Metro Planning group, to facilitate projects planned by their respective groups. Most of the requests within the Company consist of requests to relocate LVD underbuild on HVD poles. LVD underbuild refers to LVD assets that are attached to an HVD pole under the HVD lines. When an HVD pole is replaced, the LVD components need to be rebuilt and the conductors need to be transferred to, or replaced on, the new pole.

Q. What is the nature of relocation requests for make-ready work?

A. Make-ready work is initiated through the Company's pole attachment permitting process after an applicant, typically a communications company, requests to place new attachments or modify existing attachments on Company poles. The scope of make-ready work for each application is determined by field measurements and engineering analysis of existing conditions with the applicant's proposed attachment characteristics, which is evaluated to meet National Electric Safety Code ("NESC") requirements. Make-ready work can include a range of construction activities, including but not limited to raising electric conductors and equipment, adding or manipulating down guys, effectively grounding streetlight brackets, raising or lowering existing communications attachments, and pole replacements. In recent years, make-ready work has taken on increased importance due to the rollout of government infrastructure programs designed to expand access to broadband internet, particularly in rural areas.

Q. What benefits will customers realize through the Company completing work in the LVD Asset Relocations subprogram?

A. This subprogram primarily functions to serve customer requests, whether they are internal or external. However, every time old or obsolete equipment is replaced through this subprogram, reliability improves because of the new equipment and the latest standards implemented at the time. Relocations performed for HVD or substation work allow maintenance work on the facilities before a failure causes an outage. Preparing the LVD system for this work can save many customer-outage-minutes, as an outage would typically de-energize more than one circuit on these systems, with an average of 1,000 customers per circuit, for three hours or more. When LVD projects can support a planned load transfer

for HVD and substation work, the Company can perform the work in a controlled environment with little or no outage to customers. Additionally, as mentioned above, some relocation requests provide clearance for large equipment like farm machinery and road construction equipment. Without sufficient clearance, that machinery may contact the LVD system, causing an outage, putting the operator or other members of the public in danger, and causing thousands of dollars of damage. The LVD Lines Relocation subprogram ensures that municipal requests are completed by the deadline.

Q. How does the Company identify LVD Asset Relocations projects?

A. The activity in this subprogram is entirely driven by requests from both external and internal stakeholders. For all project requests, a party submits a request that includes timelines for completion if applicable, the project purpose, contact information, and any other pertinent information. For many municipal projects and large internal projects, the Company holds site meetings to gather further information.

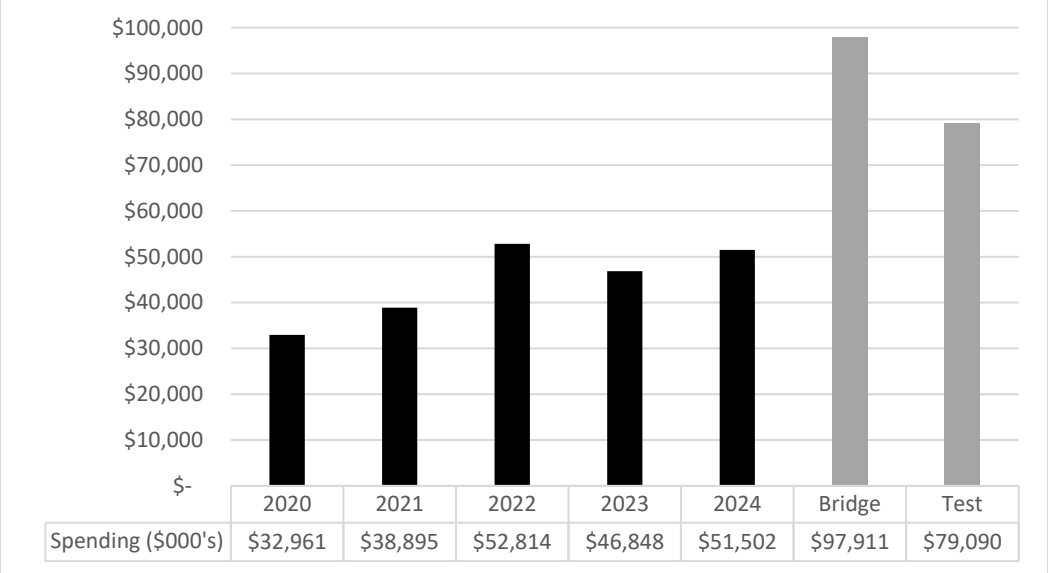
Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Asset Relocations subprogram?

A. The Company has identified known projects for the bridge period and test year, which are listed in Exhibit A-166 (JMP-1), page 1, and Exhibit A-167 (JMP-2), page 1, respectively. Due to the nature of the Asset Relocations program, only projects known in advance in the LVD underbuild relocations investment category are listed. The Company developed the projected costs of the projects in this exhibit considering estimated costs for materials and labor and the Company's previous experience performing similar projects. These exhibits also identify the location of the projects.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Asset Relocations subprogram?

A. The Company is projecting LVD Asset Relocations capital expenditures of $97,911,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 38, column (k), and $79,090,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 38, column (l). The Company's historical actual spending in the LVD Asset Relocations subprogram, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 38, and below in Figure 14.

FIGURE 14
LVD ASSET RELOCATIONS SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$32,961	$38,895	$52,814	$46,848	$51,502	$97,911	$79,090

Q. How did the Company develop its projected expenditures in this subprogram?

A. The Company is projecting that make-ready work will increase in comparison to recent history, especially as telecommunications companies request installation of new cellular and broadband equipment on poles in part driven by federal grants. Increases in spending from 2022 through the test year can be attributed to the government programs – Rural Digital Opportunity Fund ("RDOF") and the American Rescue Plan Act, which funded the

Realizing Opportunity with Broadband Infrastructure Networks ("ROBIN") grant – to install broadband to rural homes. In addition to those continuing programs, the application window for Broadband, Equity, Access and Deployment ("BEAD") grant funding is early 2025, and scheduled to start construction in 2026. These programs are expected to influence the LVD Asset Relocations subprogram through 2028. The Company also anticipates continued LVD lines that need to be relocated, proportional to the Company's work on the HVD system, to accommodate HVD projects, especially in the HVD Lines Reliability and HVD Lines Rehabilitation subprograms. In addition, the Company experienced a steady increase in expenditures from third-party and customer requests between 2020 and 2022. The Company anticipates a 1.6% expenditure increase in 2025 to relocate overhead and underground lines and services for the customer requested investment category, as shown in the equation below. These trends informed the Company's projected needs for the bridge period and the test year.

$$Growth\ Rate = \left(\frac{Present}{Past}\right)^{\frac{1}{Years}} - 1 = \left(\frac{25,444,000}{23,527,000}\right)^{\frac{1}{5}} - 1 = 1.6\%$$

The bridge period spending amount for third-party and customer-requested relocations was determined based on recent trends in the number of relocation requests. Like LVD Lines New Business, relocation requests increased by 3.2% from 2020 to 2023. The LVD Underbuild investment category spend was determined based on the projects within the 2024 HVD projected expenditures. Company witness Megan L. Hayward discusses the HVD Lines Reliability projected expenditures.

Q. Can you provide further detail on how the broadband programs discussed above will impact make-ready work?

A. These programs are expected to significantly increase the number of make-ready work orders that the Company will need to complete as part of this sub-program. This increase is shown in Figure 15 below.

FIGURE 15
MAKE-READY FIELD COMPLETE WORK ORDERS BY YEAR

Year	Make-Ready Field Complete Orders
2019 actual	1,007
2020 actual	752
2021 actual	829
2022 actual	1,236
2023 actual	1,655
2024 actual	1,640
2025 Projected	~~5,547~~ 2,689
2026 Projected	~~6,451~~ 3,119
2027 Projected	~~6,816~~ 3,307

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this subprogram will be allocated across the four investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 16 below.

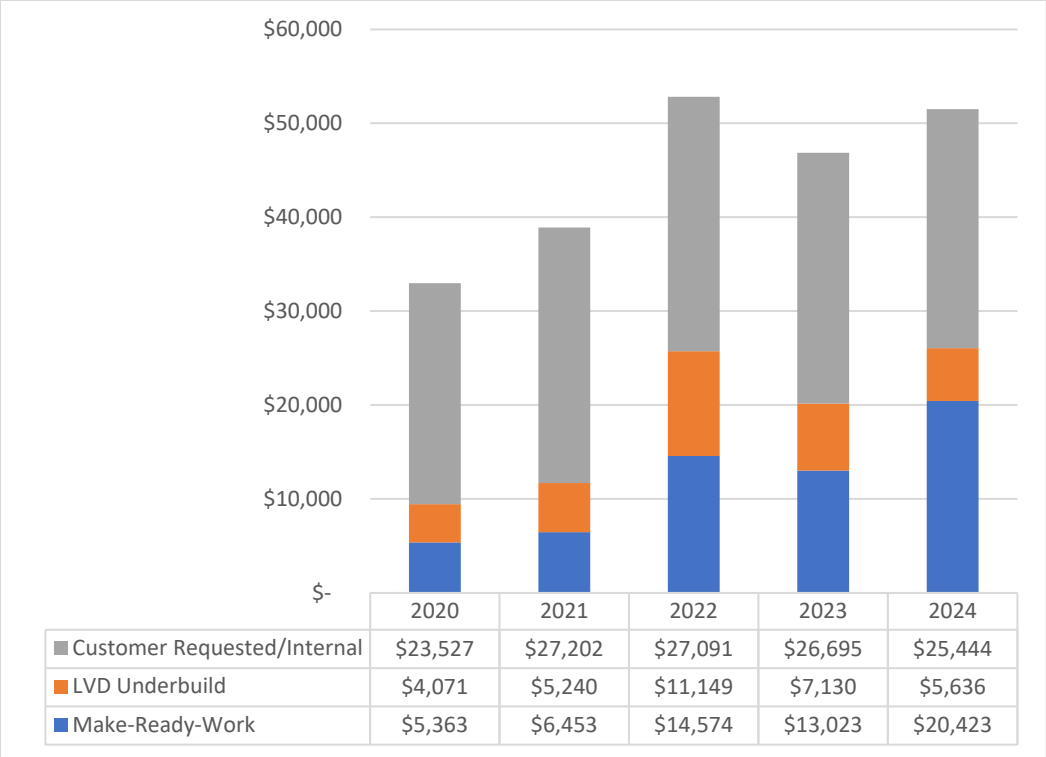
FIGURE 16
LVD ASSET RELOCATIONS INVESTMENT CATEGORY EXPENDITURES

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units
Customer requested and other internal relocations	$45,018,000	4,163	$32,341,000	3,379
LVD underbuild relocations	$7,056,000	N/A	$7,484,000	N/A
Make-ready work	$45,837,000	~~7,697~~ 3,728	$39,265,000	~~6,572~~ 3,181
Total	**$97,911,000**		**$79,090,000**	

Q. What has been the historical actual spending in the LVD Asset Relocations subprogram for the past five years?

A. The Company's historical actual spending in the LVD Asset Relocations subprogram for the past five years is shown in Figure 17 by investment category.

FIGURE 17
LVD ASSET RELOCATION 5-YEAR HISTORY



	2020	2021	2022	2023	2024
Customer Requested/Internal	$23,527	$27,202	$27,091	$26,695	$25,444
LVD Underbuild	$4,071	$5,240	$11,149	$7,130	$5,636
Make-Ready-Work	$5,363	$6,453	$14,574	$13,023	$20,423

Q. Please explain the year-over-year variation in spending in this subprogram.

A. Because investment in this subprogram depends heavily on requests for relocation, the cost and amount of relocation projects can vary. In the years of 2020 and 2021, spending by the telecommunications companies was limited. Starting in 2022, telecommunication companies increased their spending as funds from the *American Rescue Plan Act* and the *Rural Digital Opportunity Fund* became available. Additionally, the Company needed to relocate an increasing number of LVD lines in 2019 and 2022 to accommodate HVD

projects, particularly in locations where LVD lines were underbuilt on HVD structures. The Company saw an increase in customer requested relocations in 2020 and 2021 due to an increase in home remodeling work. The spending continued into 2022 and 2023 but slowed as the interest rates rose at the end of the year.

Q. Does an average unit cost accurately reflect the expected spend per project for this subprogram?

A. No. Average unit cost is not a good measure of spend to predict the cost of an individual project in this subprogram. There is a wide variance among work required as described in the previous response.

Reliability Program

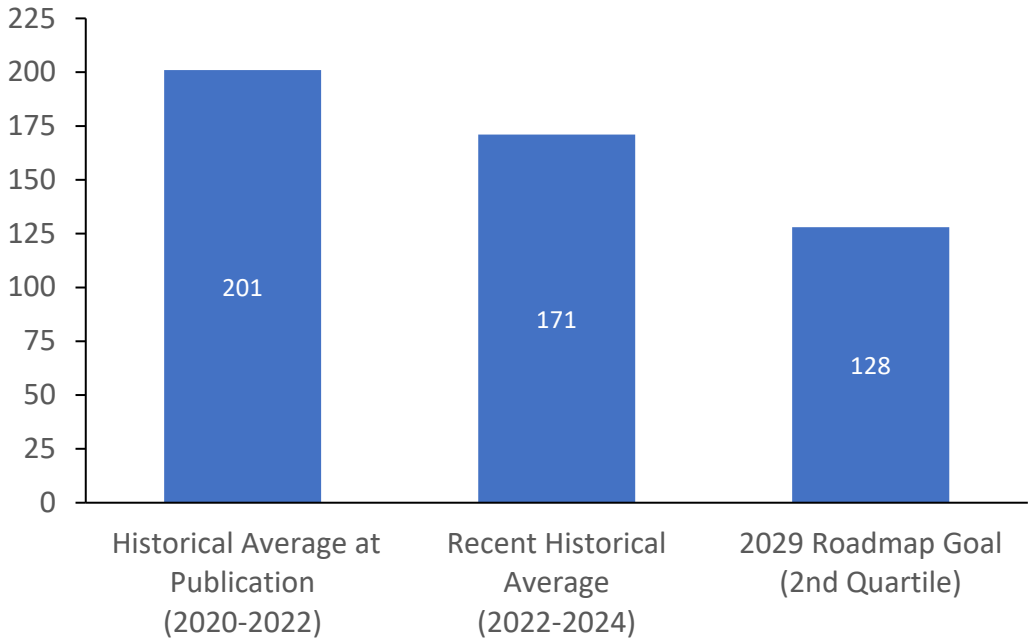
Q. What is the purpose of the Reliability Program?

A. The purpose of the Reliability Program is to ensure the long-term safe and reliable operation of the electric distribution system, and to support the Company's SAIDI glidepath, as introduced and discussed by Company witness Kelly. As Company witness Kelly explains, the Company developed the Reliability Roadmap by modeling different scenarios for increasingly severe weather and then defining a ramp-up in distribution system investment to improve reliability in the face of that worsening weather. That plan consists of four key categories of work: line clearing, hardening, inspections, and digital automation. As I will discuss in this section of my testimony, the hardening work largely takes place in the Reliability Program, particularly in the LVD Lines Reliability and Resiliency subprograms. In these subprograms, the Company is increasing investment relative to the historical levels that predated the Reliability Roadmap.

Q. Why is the Company increasing Reliability investment compared to historical levels?

A. As Company witness Kelly discusses in his testimony, the Company's scenario modeling in the Reliability Roadmap indicated that climate change will result in more severe weather and extreme heat, in turn creating increasing reliability and resiliency challenges for the distribution system, with an increase in severe weather-related outages by the early 2030s, compared to 2020 levels. Furthermore, Company witness Kelly explains that, absent the investment levels identified in the Reliability Roadmap, the Company will not be able to deliver the reliability that both the Commission and various stakeholders have indicated is needed for customers. Specifically, the Company's investments will deliver second quartile reliability performance by the end of the decade, as shown in Figure 18 below.

FIGURE 18
SAIDI EXCLUDING MEDS PROJECTIONS –RELIABILITY ROADMAP Goal



In each section of my testimony on the Reliability Program, I will explain how each investment category is aligned with the investment plan laid out in the Reliability Roadmap, leading to these SAIDI improvements.

Q. The Reliability Roadmap identifies a reliable and resilient system as one of the Company's distribution objectives. Is resiliency different from reliability?

A. Yes, but resiliency and reliability are related. *Reliability* is defined as the ability of the system to withstand normal variation and continue serving customers predictably. While reliability investments focus on the typical days of the year, when conditions are normal, resiliency investments are focused on storms and other extreme weather, which are only projected to become more frequent, as described by Company witness Kelly. A resilient electric system yields reliable customer service by withstanding these extreme storms. While investments may initially target either reliability or resiliency, the outcome of the investment will often improve both.

Q. How do you define Resiliency?

A. The Company defines resiliency as the ability of the system to withstand a major event – particularly, a large and/or extreme storm – and the ability of the system to recover from a major event where damage occurs, minimizing the needed restoration and repair time.

Q. Are reliability and resiliency differentiated within the Reliability Program?

A. Among LVD Reliability Program investments, most subprograms are primarily focused on reliability improvements, targeted SAIDI reductions on blue-sky days. The Resiliency subprogram is focused primarily on resiliency investments, which may not result in major blue-sky SAIDI reductions, but are designed to harden the system and reduce the impact of major weather events on customer outages.

Q. How does the Company measure the benefits of Reliability program investments?

A. There are various means of measuring reliability benefits that will be discussed at various points in my testimony, but one of the most important is the customer-outage-minute benefit.

Q. What is meant by a customer-outage-minute benefit?

A. Customer-outage-minutes, sometimes shortened to customer-minutes, is a mathematical product of the number of customers that experience an extended outage of electrical service and the duration of outage measured in minutes. These numbers are gathered through the Company's outage management systems for each outage. For example, a failure on the LVD system that interrupts electrical service to 100 customers for 170 minutes would accrue 17,000 customer-outage-minutes. A reliability project will reduce this number by either reducing the probability of failure leading to an outage, the duration of the outage, and/or the number of customers impacted by the failure and subsequent outage. The planning engineer will determine the amount of savings based on both the historical outage data of that part of the system and the expected effectiveness of the solution selected. For example, if the historical average customer-outage-minutes of an LVD zone was 20,000 per year and the proposed project would reduce the probability of that outage by 70%, the customer-outage-minutes avoided by completing the work would be 14,000 (70% of 20,000). In this way, the benefit of a distribution reliability project can be quantified.

Q. What portion of the Reliability Program will your testimony discuss?

A. My testimony will focus on the following LVD subprograms.

(i) LVD Lines Reliability;

(ii) LVD Repetitive Outages;

(iii) LVD Lines Rehabilitation; and

(iv) Resiliency.

Projected spending and benefits are explained in detail in the subprogram sections below.

LVD Lines Reliability

Q. What is the purpose of the LVD Lines Reliability subprogram?

A. The LVD Lines Reliability subprogram includes projects to ensure the long-term safe and reliable operation of the Company's LVD lines. The subprogram includes a diverse range of projects that are designed to address concerns on a given circuit or circuits.

Q. How does the Company identify LVD Lines Reliability projects?

A. The Company uses several critical inputs and analyses to aggregate multiple data sources to best target and prioritize reliability issues. The analyses used help identify specific areas to target investments based on probability of future issues and help prioritize projects that will deliver the greatest reliability improvements.

Q. What is the primary input in this process?

A. The primary input for deciding where to invest is data provided by the Reliability Analytics Engine ("RAE"). The RAE data is used to help the Company evaluate how to maximize the reliability benefit to customers through reduced outages.

Q. Please describe the RAE.

A. The RAE is a database used to analyze outage incident history and electric operations performance. The RAE arranges multiple data points in a manner that allows key reliability metrics (e.g., System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and Customers Experiencing Multiple Interruptions ("CEMI")) to be calculated at varying levels of granularity. By combining

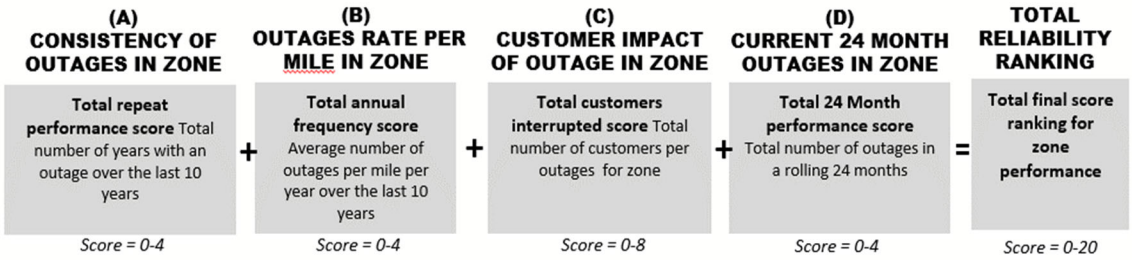
data from various sources, the RAE can also construct a complete timeline for all incidents from initial outage to final restoration. This detailed timeline breaks down an outage into analysis, dispatch, travel, and repair process steps, and calculates the time spent in each step. The RAE also includes other sources such as line clearing data, callout success rates, and historical project spending. These can be combined with other data to analyze reliability. The RAE also produces monthly zonal analysis data that is reviewed by each area's LVD circuit planner. This data is analyzed to determine zonal impact to LVD system reliability.

Q. What conclusions does the Company draw from this RAE analysis?

A. By analyzing historical outage data across the LVD system, identifying trends, and assessing zones with the greatest potential for reliability improvement, the RAE provides a ranking of zones to target to maximize SAIDI reduction. Data is analyzed in four ways —consistency of outages, outage rate, customer impact, and current year outages—to determine the score for any given zone compared to all other zones on the LVD system statewide.

The results of the analysis are totaled to determine the final score for any given zone, as shown in Figure 19. Once reliability inputs are used to identify zones to target on the LVD system, reliability projects are developed, evaluated, and prioritized to develop an investment plan that maximizes the reliability benefit for customers.

FIGURE 19
ZONAL RANKING FORMULA



Q. Does the Company consider anything besides RAE output when prioritizing projects?

A. The RAE is but one tool – albeit a tool that pulls in many diverse types of data – that helps create a zonal health score that then informs prioritization of projects. The zonal health score considers important factors in prioritizing reliability projects, including consistency of outages in the zone, outages rate per mile in the zone, customer impact of the outages in the zone, and the current 24-month outages in the zone. Thus, the Company uses the zonal health score to identify customers that are experiencing the poorest reliability and prioritizes projects to improve reliability for those customers. The best use of Company resources is for the Company to seek to address those areas that are experiencing the poorest reliability. The Company typically does this on a "least-cost-best-fit" basis, which is commonly recognized in the industry as an appropriate means for evaluating reliability investments. Least-cost best-fit analyses consider the desired functionality or capability on the distribution system, or the safety, reliability, or regulatory goals, along with the lowest cost way to accomplish these goals.

Q. Why does the Company utilize least-cost-best-fit analyses for this sub-program?

A. The Company recognizes that interruptions to customers is a problem worth solving. Using least-cost best-fit to select the method for addressing reliability concerns is preferrable to relying on cost-benefit ratios, which could result in concluding that a project that does not

pass a certain threshold is not worth completing, thus leaving the problem of those customer interruptions unaddressed.

Q. What other information does the Company consider when identifying potential LVD Lines Reliability projects?

A. The Company considers other circuit characteristics, such as car-pole accident history and downed wires, to potentially add or reprioritize the list of projects. In addition, the Company uses advanced metering infrastructure ("AMI") data to identify voltage deviations on the circuit, and to create projects to ensure service to customers is delivered within the voltage range specified in Company tariffs.

Q. What investment categories are included in the LVD Lines Reliability subprogram?

A. The LVD Lines Reliability subprogram consists of five investment categories:

(i) targeted circuit improvements;

(ii) pole replacements;

(iii) ATR loops;

(iv) circuit exit enhancements; and

(v) ROW and easement acquisition.

Targeted Circuit Improvements

Q. What does the Company include in targeted circuit investments?

A. Targeted circuit improvements include several project types with customized solutions to address specific reliability concerns. The Company employs four distinct strategies within this investment category including:

(i) reducing the amount of non-standard voltage on the distribution system;

(ii) zonal health investments;

(iii) converting open-wire secondary to multiplex; and

(iv) rejuvenating vintage underground cable.

The Company has been doing some amount of the kind of work contained in each strategy for many years, but only began calling out each strategy separately in Case No. U-21585, following the language used in the 2023 filing of the Reliability Roadmap. This allows the Company to provide more detail and transparency around the diverse types of work in the targeted circuit improvement investment category than was provided in earlier electric rate cases.

Reducing Non-Standard Voltage

Q. How does the Company reduce the amount of non-standard voltage?

A. Non-standard voltage conversion is discussed in the Reliability Roadmap. The Company converts distribution circuits and substations energized at non-standard voltages to one of the three standard voltages that Consumers Energy operates. The Company presently operates 13 general distribution voltage systems; the three standard operating voltages are 4.8/8.32 kV, 7.2/12.47 kV, and 14.4/24.9 kV grounded-wye. Systems dedicated to serving a single customer site are not within the scope of this category.

Q. Are there additional benefits of reducing the amount of non-standard voltage beyond improving reliability?

A. Yes. First and foremost, reducing the amount of non-standard voltage provides safety benefits, as described in the Reliability Roadmap and as discussed by Company witness Kelly. Also, in addition to improved reliability through customer-outage-minute savings, further benefits include:

- Reduced system losses and increased system line capacity – Converting delta systems to grounded-wye reduces load current on primary lines, thereby

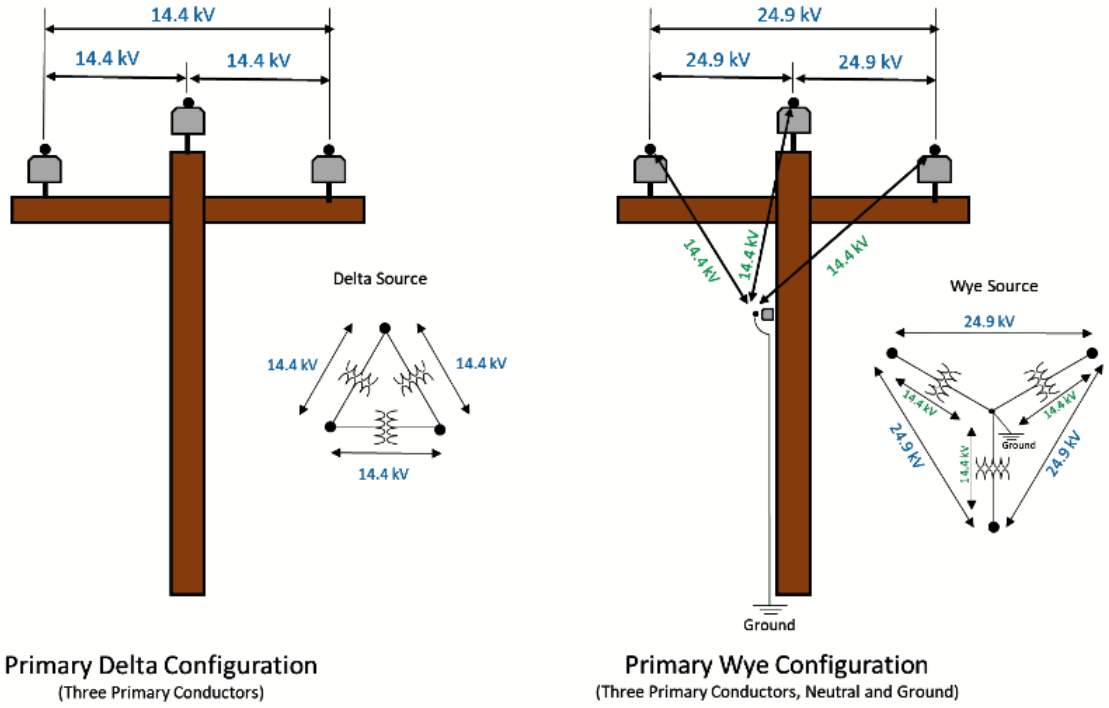
increasing available line capacity. For the same electric load, the grounded-wye system will carry 58% of the load current that the delta system carries (e.g., a 400 Amp rated conductor carrying 360 delta Amps (90% loaded) will carry 208 wye Amps (52% loaded) after the conversion). Since the amount of loss in an electric system is proportionate to the square of the load current, reducing the load current by voltage conversion lowers the electric loss associated with that portion of the electric system. Further loss reduction is typically realized through voltage conversion as older transformers and isolators are replaced as part of the voltage conversion project.

- Reduced number of interrupted customers for single-phase faults – When a single-phase fault occurs on the delta system, two primary phases are disrupted, interrupting two-thirds of the customers; when a single-phase fault occurs on the grounded-wye system, only one phase trips, interrupting one-third of the customers.

- Increased system load transfer capability – Circuit conversions create the opportunity to improve transfer capability between like systems and build a platform for increased distribution automation and smart grid systems.

- Reduced equipment inventory – Eliminating the non-standard line transformer inventory would reduce and eventually eliminate the need to maintain non-standard line transformer inventory. Non-standard transformers are more difficult to maintain in inventory in sufficient quantities, because suppliers produce fewer of them. The Company experienced a shortage of transformers, exacerbated by the need for non-standard voltages, in the past couple of years leading to delays in connection of new customers.

FIGURE 20
ILLUSTRATION OF DELTA VS. WYE CONFIGURATIONS



Zonal Health Investments

Q. What are zonal health investments?

A. Zonal health investments are addressed in the section of the Reliability Roadmap on LVD circuit health. The Company's analysis has shown that 91% of customer interruptions happen on just 25% of line miles. Because of this, the Company focuses on or "targets" individual zones when assessing LVD asset health and mitigating the risk, instead of whole circuits. The Company assesses the health of each zone using the zonal health assessment rubric that is explained in the Reliability Roadmap and Figure 19 earlier in my direct testimony.

Q. When did the Company begin doing zonal health improvement work?

A. The Company began doing zonal health improvement work in 2013.

Q. Can you provide some illustrative examples of how zonal health investment projects are selected?

A. Test period examples include:

- Alger Substation, Skidway Circuit has a zone score of 18. The zone experienced seven outages in 2024. The project will benefit 1,647 customers. This project is to install 336 kcmil aluminum conductor steel reinforced ("ACSR") for one mile to split the load between the Skidway and Forest Lake circuits both on Alger Substation. This will reduce customer counts on one circuit, reduce exposure miles, and allow for future voltage conversion projects for surrounding non-standard voltage substations. This project was selected due to the high Zone Score, 2024 outage count, and the future benefits it can provide to the surrounding substations.

- Camelot Lake Substation, Loomis Circuit, LCP 132 has a zone score of 17. The zone has experienced seven outages in 2024, and one outage as of June 2025. The project is to move 1 mile of line out of deep right of way ("ROW") to the roadside and install tree wire at the new location. The project will benefit 207 customers. The project was selected due to the high zone score, and high outage count.

- Cowan Substation, Ramsdell Circuit has a zone score of 19. The zone experienced two outages in 2024 and two outages as of January 2025. The project is to replace the existing conductor with tree wire for 1.2 miles. The project will benefit 1,386 customers. The project was selected for its high zone score, and consistent outages..

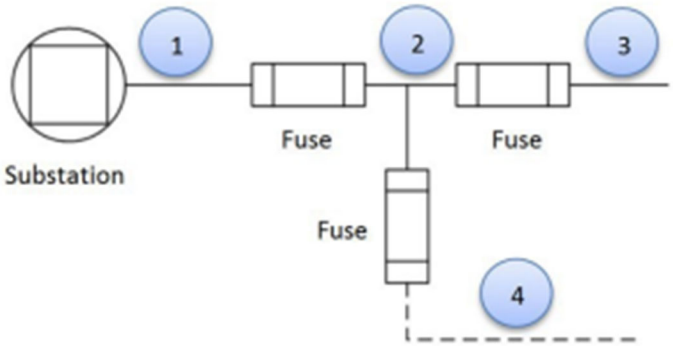
- Frankfort Substation, Gateway Circuit, Zone 5554: This project will reconductor approximately 1,300 feet of #8 copper conductor with #4 ACSR and replace poles to current standards. #8 copper conductor is considered a Hazard Conductor due to its fragility. It easily breaks, especially during storms, and can be hard to splice if it continues to be brittle while crews are handling it. While the zone score for this zone is only 6, the Company is selecting this project due to concerns with the #8 copper conductor. This project will benefit 46 customers.

- The Gilson Substation Rock Lake Circuit Zone 801 project was selected as a voltage conversion project. This zone has 6.8 miles of 11 kVA delta and this project will convert 52 customers to 14.4/24.9 kVA wye. This will eliminate 6.8 miles of non-standard voltage.

Q. Can you provide an illustration of how circuits are subdivided into zones?

A. Yes. Please refer to Figure 21 below, which shows a circuit subdivided into four zones. The Company has approximately 137,000 protective zones on its LVD system.

FIGURE 21
ILLUSTRATION OF DELTA VS. WYE CONFIGURATIONS



Q. How do zonal health investments create benefits for customers?

A. Zonal health investments improve the reliability of the Company's LVD system by reducing the likelihood of an additional interruption over the next five years or more. A zone targeted for improvement can include multiple protective device zones or a single protective device zone. When the Company is aware that a circuit has deficiencies, based on outage data, then the Company inspects the overhead lines on affected circuits to identify appropriate solutions to improve reliability on those circuits. Solutions in zonal health investments include, but are not limited to:

- Replacing equipment at the end of expected life, including poles, cross-arms, switches, and conductor (overhead and underground);
- Installing new system protection devices, including fuses, switches, and reclosers to reduce the size of the zone, and to reduce the number of customers impacted by an interruption (see Figure 22 for an illustration of this work);
- Installing upgraded poles and composite cross arms to meet increased design and construction standards;

- Upgrading conductor at risk for contact with trees, typically in heavily wooded areas, to tree wire or aerial spacer cable to provide better tree protection. Both aerial spacer cable and tree wire are insulated wires that mitigate contact with trees and associated interruptions;

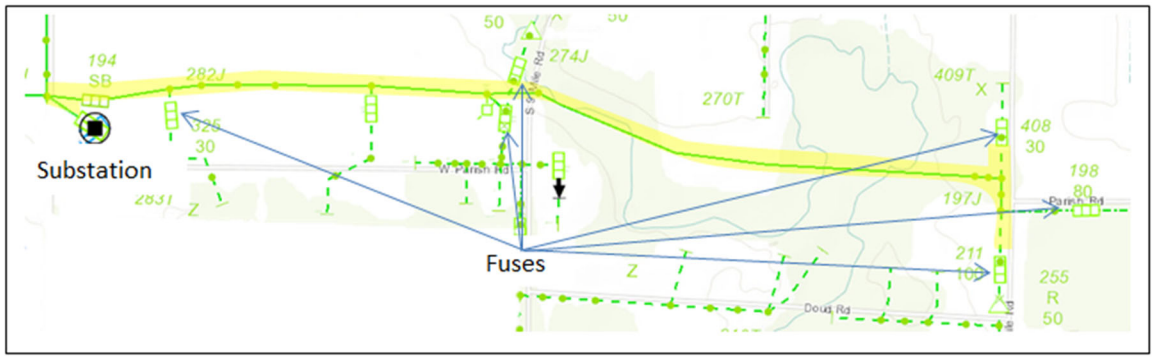
- Restoring underground cable that is no longer looped to re-establish redundancy;

- Improving system protection coordination and reach – following certain upgrades, protective devices may no longer coordinate (a systematic application of devices to ensure clearing of permanent faults) or reach (the zone or area of protection in which a fuse, recloser, or breaker will open within an acceptable timeframe);

- Improving the system's capability to isolate and transfer load for improved restoration time; and

- Improving voltage quality through equipment upgrades, reconductoring, circuit reconfiguration, and phase balancing.

FIGURE 22
ILLUSTRATION OF ZONE PROTECTION DEVICES



Q. Has the Company adjusted its LVD Lines Reliability approach?

A. Yes. As described earlier in the LVD Lines Demand Failures section, the Company took a new approach to LVD overhead line assessments in 2022, including completing the addition of high-value lateral fusing. This decreases SAIDI by isolating future faults to smaller sections of line, minimizing the number of customers affected per interruption, and minimizing the amount of time required for LVD line crews to patrol and identify the cause of the outage. EPRI validates this approach in their technical report, *Distribution Grid*

Resiliency: Prioritization of Options[5], Appendix D, page 13, noting that "[a]pplying sectionalizing devices can reduce sustained interruptions per mile by reducing the number of customers who are outaged by the initial event. Only those customers downstream of the protective device nearest the fault location are affected." The Company plans to effectively complete this fusing effort in 2025.

Q. Can the Company demonstrate the benefits of zonal health investments?

A. Yes. The Company has measured the performance of circuit improvement projects by comparing the three years of outage history of the zone prior to investment to the outage history for the one to three years after investment. Zonal health improvement work has produced, on average, a 53% reduction in outages. Figure 23 illustrates zonal performance improvements following targeted circuit improvement projects in 2019 through 2023.

FIGURE 23
AGGREGATED IMPACT OF TARGETED CIRCUIT IMPROVEMENTS ON ZONAL PERFORMANCE

Project Year	Zonal Projects	Prior 3-Year Average Outages	Post 1-Year to 3-Year Average Outages	Percent Improvement
2019	151	280	94	66%
2020	146	206	59	71%
2021	249	347	132	62%
2022	1,394	199	119	40%
2023	2,884	274	195	28%
Weighted Average Improvement				**53%**

[5] *Distribution Grid Resiliency: Prioritization of Options*, https://www.epri.com/research/products/3002006668

Q. Can you discuss the trend in percentage improvement following targeted improvement projects?

A. When interpreting Figure 23, it is important to note that the "zonal projects" column includes fusing work in 2022 and 2023 in addition to more traditional zonal health improvement work, which is why the number of projects increases by so much. Fusing projects do not necessarily reduce the number of outages on a circuit, but they do reduce the number of customers impacted by any particular outage. This impacts the before and after outage numbers in the figure, and therefore the calculated percentage improvement. It is important to note that traditional zonal health improvement work delivers substantial outage reduction benefits, as shown in the data from 2021 and earlier.

Q. Please provide some specific examples of recent zonal health improvement projects.

A. Recent examples of these projects include:

- The overhead conductor on Cedar Springs Substation, Nelson Circuit, Zone 150, was faulting two to three times per year between 2015 and 2021, with four outages in 2020. A majority of the outages were caused by trees on blue sky days and during storms. Each outage caused interruptions to 454 customers. In June 2022 the overhead conductor was replaced with tree wire to prevent outages. This zone has not caused an outage since March 2022. Between 2022 and 2025, this has saved approximately 177,000 customer-outage-minutes annually.

- The overhead conductor on Foreman Substation, Cumberland Circuit Zone 646, had two to five outages every year between 2015 and 2020, with another four outages in 2022 averaging 62,500 customer-outage-minutes annually. The causes were trees, inside and outside of ROW, and storms affecting 96 customers. In April 2023, the Company installed 0.8 miles of tree wire to minimize the tree related outages. These customers have not experienced an outage originating in this zone since the project's completion.

- The underground cable on Calvin Substation, Rosemont Circuit, Zone 654, was faulting once each year from 2015 through 2017, interrupting approximately 30 customers. This underground section was selected for underground rejuvenation to inject the cable and replaced segments of cable in 2018 and 2019. Subsequently, those customers experienced no interruptions in 2018

through 2023 due to this issue, saving approximately 43,000 annual customer-outage-minutes.

- Alamo Substation, Pine Grove Circuit, Zone 844, experienced three outages in 2021 and five outages in 2022, mainly due to tree issues, interrupting approximately 1,030 customers. In 2024, the Company upgraded a section of three-phase conductor to tree wire in an area that has lots of tree overhang. Shortly after this project was constructed, a large tree fell on the new tree wire. The tree wire held up the tree, subsequently saving approximately 227,300 customer-outage-minutes. The photo in Figure 24 below shows the tree being supported by the new tree-wire.

FIGURE 24
LVD TREE-WIRE CONSTRUCTION SUPPORTING A FALLEN TREE



Q. Are there specific benefits to projects that add lateral fuses?

A. Yes. The Company's analysis of lateral fuse additions completed in 2022 shows that these fuses prevented 43 circuit lockouts and avoided approximately 4.6 SAIDI minutes,

excluding MEDs, in 2022. The lateral fuse additions completed have avoided approximately 5.4 SAIDI minutes, excluding MEDs, in 2023 and 6.5 minutes in 2024. Continued addition of lateral fuses in 2025 will further reduce SAIDI.

Q. Does the Reliability Roadmap define a long-term workplan for zonal health investments?

A. Yes. In the Reliability Roadmap, the Company explains a plan to address all zones with a zonal health score of 10 or greater, meaning each of these zones will need investment. The 2023 Reliability Roadmap provided a plan to do this work over a period of 20 years, with a ramp-up in investment to addressing approximately 280 zones per year. However, as Company witness Kelly explains in his direct testimony, the Company is adjusting this plan to maintain the same SAIDI glidepath while accounting for increased line clearing work, and the Company is now only ramping up to approximately 85 zones per year (this increased line clearing work is tied, in part, to recommendations from Liberty Consulting Group ("Liberty") in their audit of the Company's distribution system, filed in Case No. U-21305 in September 2024). This change is reflected in the test year projections for zonal health investments in the instant case. In every instance, the Company is planning projects in zones that have been specifically identified as needing investment to deal with reliability issues.

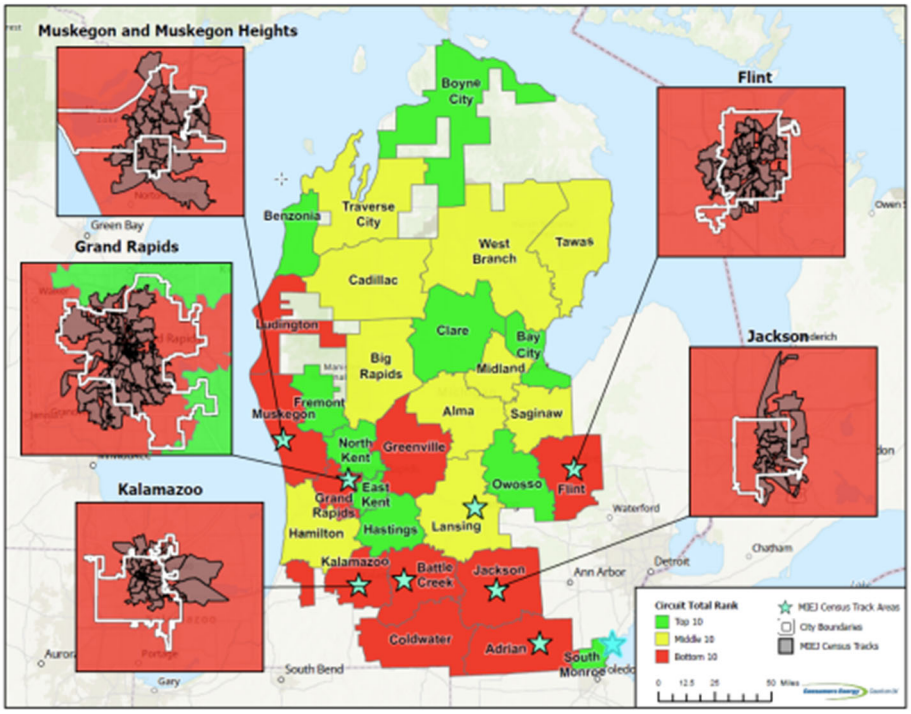
Converting Open-Wire Secondary to Multiplex

Q. What are the issues facing secondary conductor on the Company's distribution system?

A. As discussed in the Reliability Roadmap, secondary assets—located between the distribution transformer and customer meter—are more challenging to repair than primary

assets. This challenge is most prevalent on open-wire secondary, much of which is approaching the end of its life, and is brittle and not easily repaired, and thus is more vulnerable to tree damage. Individual outages on the secondary system may not affect large numbers of customers, but they are high-frequency and long in duration. As demonstrated in Figure 25 below, open-wire secondary has a disproportionately high impact on vulnerable communities.

FIGURE 25
SERVICE CENTER REGIONS WITH SECONDARY CIRCUIT PERFORMANCE



Q. How does the Company plan to address these concerns?

A. As explained in the Reliability Roadmap, the Company plans to programmatically convert its open-wire secondary to multiplex secondary, focusing on circuits with the highest risk scores, while ensuring equitable investments into vulnerable communities. The targeted secondary circuits in the instant case are included in the project list in Exhibit A-166 (JMP-1), page 12; and in Exhibit A-167 (JMP-2), page 6. In Case No. U-21585, the

Commission approved one half of the Company's initially proposed investment in open wire secondary conversion, which equated to approximately $14.4 million per year. The Company's proposed investments in the instant case are in line with this approved level. The Company's planned investments in the instant case focus heavily on vulnerable communities first; following the Commission's disallowances for these investments in Case No. U-21585, the Company is prioritizing using the remaining dollars to invest in those communities. The difference between open-wire secondary and multiplex secondary is shown in Figure 26 below.

FIGURE 26
MULTIPLEX VS. OPEN WIRE SECONDARY



Q. How does this conversion work benefit customers?

A. The most important benefit of doing this will be to improve safety by reducing the occurrence of difficult-to-repair wire downs, particularly in vulnerable communities.

The new multiplex secondary will also have more capacity, reducing the number of future upgrades that would be needed when customers adopt new technologies, such as heating electrification or electric vehicle ("EV") charging, again helping customers in vulnerable communities to better access those opportunities. Typical open wire on the secondary system is able to carry between 95 Amps and 175 Amps, while multiplex is rated

for 195 Amps to 320 Amps. For homes with 200 Amp panels, open-wire secondary may be approaching maximum capacity, which will not allow future growth for technologies such as EVs, electrification, and distributed energy resources ("DERs").

While the impact to systemwide SAIDI is modest, the outage duration benefits for the impacted customers will be more substantial.

Vintage Underground Cable Rejuvenation

Q. What are the issues facing vintage underground cable on the Company's system?

A. Vintage underground cable is discussed in the Reliability Roadmap. While underground distribution provides many benefits, particularly for resiliency, the cable eventually begins to degrade, which leads to a heightened risk of failure. This is a particular issue for 15 kV vintage cable that dates to earlier than the 1980s, which makes up approximately 2,500 miles of the 9,500 miles of underground primary cable on the Company's system. This vintage cable is also unjacketed, leaving the neutral conductors exposed to accelerated deterioration from exposure to soil and moisture. Figure 27 below illustrates the locations of this 15 kV vintage underground cable, along with locations of outages over the past three years. Figure 28 illustrates the SAIDI contribution of the underground system, highlighting that the most critical areas are in Grand Rapids, Flint, Traverse City, and Kalamazoo.

FIGURE 27
UNDERGROUND CABLE: LOCATIONS OF 15 KV CABLE

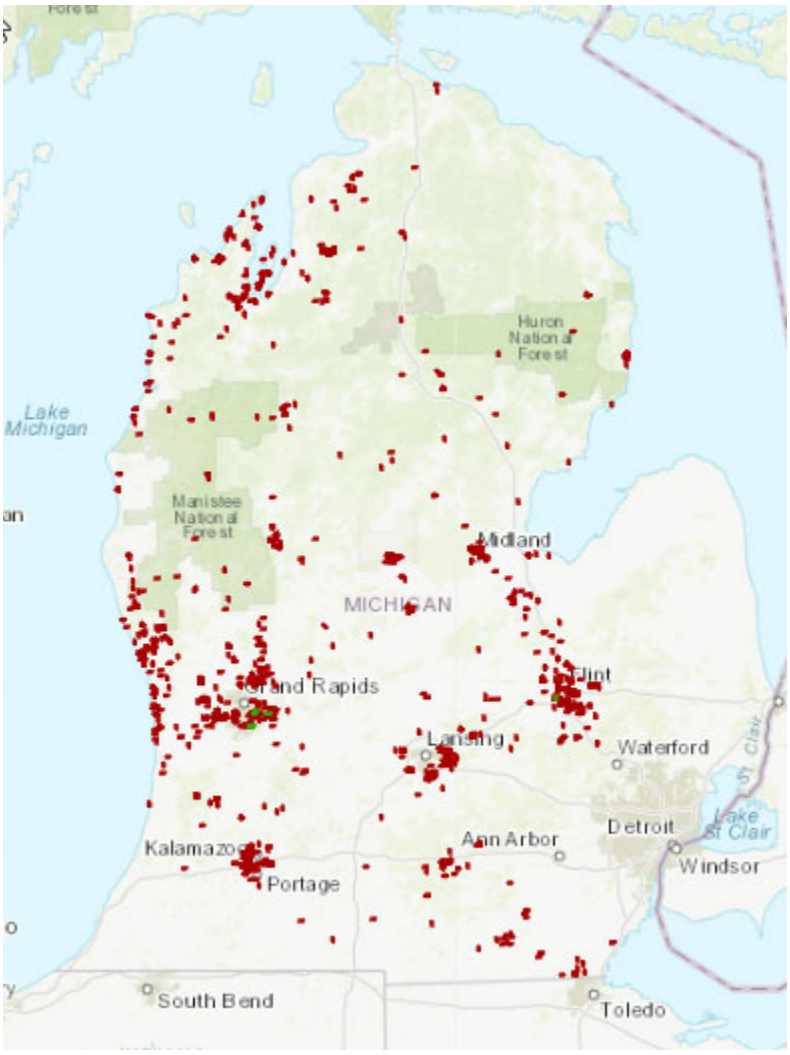
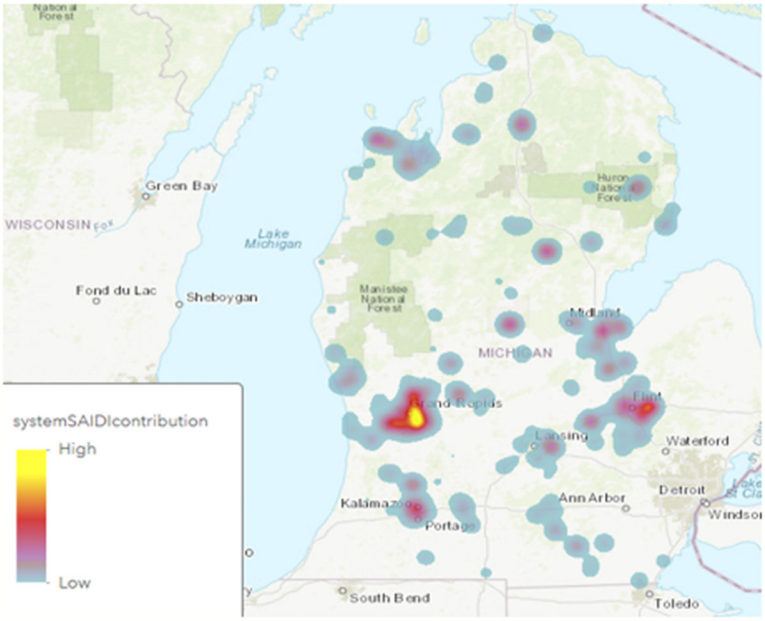


FIGURE 28
SAIDI CONTRIBUTION OF UNDERGROUND PRIMARY



Q. How does the Company plan to address these concerns?

A. To address these challenges and ensure that existing undergrounded lines continue providing resiliency for customers, the Company has begun using cable injection to rejuvenate the underground cable. This innovative process involves injecting a fluid insulation into the cable that then solidifies. This is less expensive than completely replacing the cable and is expected to extend cable life by a minimum of 25 additional years. Initially, the Company concentrated these investments in Grand Rapids and Flint because it has been most cost-effective for contractors to complete all work in one area before moving on to new locations. The Company will begin working in Traverse City as well in 2026. As explained in the Reliability Roadmap, the Company plans to rejuvenate all 15 kV cable installed between the 1960s and 1980s, over a period of nine years beginning in 2025, with a ramp-up to investing up to $165 million each year.

It is notable that Liberty's distribution system audit highlighted the successes of vintage underground cable rejuvenation. Specifically, they wrote, "Consumers has had success to date in using rejuvenation, supported by long-term guarantees of effective operation by the contractor who performs the work." Liberty concluded that this work "reflects a sound means for addressing vintage underground cable reliability problems."[6]

Pole Replacements

Q. What are the challenges currently facing LVD poles on the Company's system?

A. The Company's LVD system includes over 1.5 million poles. Pole replacements in the LVD Lines Reliability subprogram are completed based on two primary types of inputs. First, poles are replaced in response to prior inspection results from previous years that identified poles at risk of failure. The Company evaluates the results of those pole inspections to determine if a simple pole replacement is required, and further evaluates inspection results to determine if an entire pole line should be replaced or relocated to improve reliability. The Company has had a backlog of poles identified in previous years' inspections for some time, and has been working through this backlog through pole replacement projects each year.

Second, following the development of the Reliability Roadmap the Company is starting a program of groundline inspection of poles.

Q. What is groundline inspection of poles?

A. As specified in the Reliability Roadmap, the Company plans to replace all rejected poles identified either through a groundline inspection on a 12-year cycle or through the regular two-year visual inspection cycle of whole circuits. While these inspections are underway,

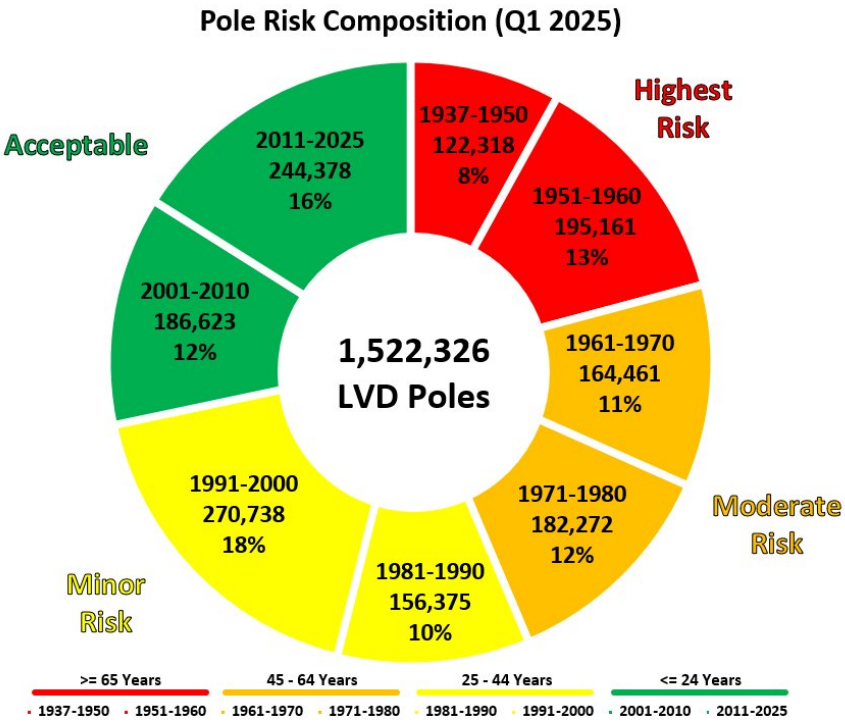
[6] Liberty Final Report Part Two, pg. 69, September 23, 2024 in Case No. U-21305

the Company will continue to replace LVD poles identified in inspections that have not yet been completed, as described above. Based on system data, the Company estimates that approximately 10% of the poles on the LVD system will be classified as rejected based on these inspections, and the Company therefore projects that these inspections will identify 12,500 LVD poles per year for replacement. This anticipated rejection rate is based on known data about the vintage of poles on the Company's system, and the typical rejection rates of poles of a given vintage. A breakdown of the Company's pole vintage is shown in Figure 29 and a breakdown of LVD pole risk is shown in Figure 30. The highest risk poles carry a rejection rate of 15% or greater, and moderate risk poles carry a rejection rate of 10% to 15%.

FIGURE 29
LVD POLE VINTAGE BREAKDOWN

Vintage	Count	Percentage
2001-2025	431,001	28.31%
1981-2000	427,113	28.06%
1961-1980	346,733	22.78%
1960 and older	317,479	20.85%

FIGURE 30
LVD POLE RISK BREAKDOWN – Q1 2024



Regardless of how a pole was identified as being in need of replacement, the replacement of a pole prior to failure avoids the interruption of electrical service to customers and is considerably less expensive than replacing a pole after it has already failed.

In addition to reliability benefits, replacing poles prior to failure delivers significant benefits for public and employee safety. Falling poles can create a major public safety hazard, threatening both people and property. Furthermore, poles in poor asset health present major safety hazards for lineworkers who may need to climb the pole during restoration work, particularly if the pole gives way under the lineworker's weight.

Q. Are any pole replacements based on age alone?

A. No. This was contemplated in the 2023 version of the Reliability Roadmap, but Liberty's audit concluded that replacing all LVD poles greater than a certain age was not warranted. The Company concurs with this finding of the audit, and the Company has correspondingly

reduced its projections of how many LVD poles will need to be replaced in future years from what was shown in the 2023 Reliability Roadmap.

Q. Is the Company taking any other actions to improve LVD poles?

A. Yes. As discussed on page 70 of the Reliability Roadmap, over time the Company has upgraded its minimum pole standards for the LVD primary system from Class 6 to Class 3. As the Company replaces poles, it is installing poles that meet the new standard. These larger Class 3 poles can endure wind gusts of up to 141 MPH without ice, or up to 71 MPH when there is a half-inch of radial icing thickness. The Company no longer uses any Class 5 or Class 6 poles in new construction or when replacing existing poles during storm restoration. Furthermore, the Company began installing ductile iron poles as an alternative to wood poles starting in 2024 for targeted locations. The ductile iron poles to be installed are an equivalent to a Class 1 wood pole and will have a longer design life in comparison to wood poles.

The difference in pole class capacities is shown in Figure 31 below. Improved pole standards improve resiliency because poles are most challenged by external forces leading to failure during severe weather rather than on blue-sky days.

FIGURE 31
2023 NESC CODE[7]

No Significant Pole Deterioration as Noted in NESC Table 261-1			
NESC Grade C Construction - LVD - NESC 250C&D Load Factors			
Pole Size Minimum	No ICE, Max Wind Speed Prior to Failure (mph)	½ Inch Ice, Wind Speed Prior to Failure (mph)	1 Inch Ice, Wind Speed Prior to Failure (mph)
Class 6	109 mph	54 mph	39 mph
Class 5	116 mph	57 mph	43 mph
Class 4	129 mph	64 mph	49 mph
Class 3	141 mph	71 mph	54 mph
Class 2	157 mph	79 mph	60 mph
Class 1	170 mph	86 mph	67 mph

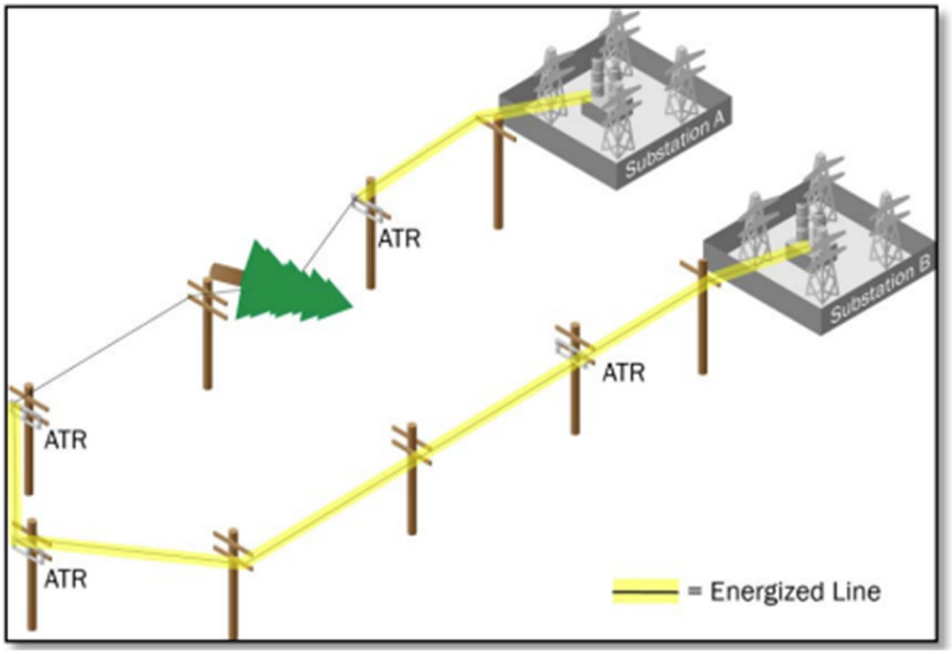
ATR Loops

Q. What are Automation Transfer Recloser ("ATR") Loops?

A. As discussed, beginning on page 81 of the Reliability Roadmap, an ATR Loop is a set of reclosers installed between adjacent circuits that work simultaneously to automatically restore power to many impacted customers when power loss is detected. Figure 32 below shows how ATRs maintain power for a large part of the system following an incident that would have caused more interruptions to customers.

[7] 2023 NESC, linear analysis, 1/0 ASCR 3 phase conductor with #4 ACSR Neutral, 350-foot spans, 45-foot pole lengths.

FIGURE 32
ILLUSTRATION OF ATR LOOP



Reclosers are single-phase or three-phase interrupting devices installed on electric distribution lines for circuit sectionalizing. Reclosers typically have a predetermined sequence of operation, tripping several times before locking out in the open position. An ATR Loop recloser control includes additional programming beyond a standard recloser. This programming automatically opens and closes the strategically placed reclosers to enable impacted customers to be fed from the adjacent source within the loop. This automated, fast response is the key factor driving customer reliability benefits.

ATR Loops have historically been installed as part of Grid Automation/ Modernization, but the Company has moved this work into the LVD Lines Reliability subprogram because it is now a well-established practice, and is incorporated into the Company's standard suite of reliability solutions. ATR Loops also provide a resiliency benefit by allowing the system to better withstand major weather events, but since they

also provide a benefit to blue-sky reliability, they are included in LVD Lines Reliability rather than in the Resiliency subprogram discussed later in my direct testimony.

Q. What historical benefits have ATR Loops provided customers?

A. The Company's first ATR Loop was installed in 2010 and, as of March 2023, there were 154 ATR Loops in service providing over 216,000 customers with a self-healing smart grid that prevents or minimizes the impacts of outages. Figure 33 shows the previous five years of tabulated actual benefits.

FIGURE 33
ATR LOOP HISTORICAL RELIABILITY BENEFITS

Year	Customer-Outages Prevented	Customer-Outage-Minutes Avoided
2019	34,333	10,334,000
2020	33,172	9,131,000
2021	36,098	23,375,000
2022	63,359	18,222,000
2023	69,339	18,059,000
Total	**236,301**	**79,121,000**

Circuit Exit Enhancements and ROW Projects

Q. What work does the Company include in circuit exit enhancements?

A. The Company installs circuit exit switches on each phase outside the substation fence, providing additional safety by creating an isolation point for line workers in case the substation (and substation equipment) becomes energized. If the substation becomes energized without having the circuit exit switches opened, the line workers could be at serious risk of contact with an energized line while working on that line.

Q. What work is included in ROW projects?

A. This investment category is used to procure necessary land or land rights for LVD projects, including both lines and substations. Acquiring the necessary land rights is essential to

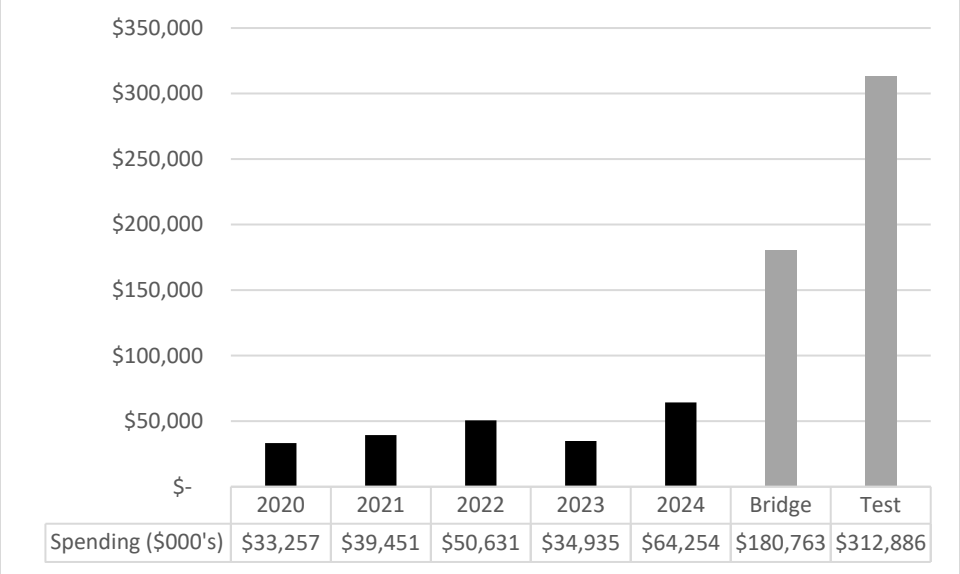
enabling LVD line projects across multiple capital subprograms. These projects are critical to prepare for LVD construction and adequately support the project that is depending on the new rights. New rights are required for new LVD line, LVD line relocation or rebuild off-center, and improved easements where rights are determined to be inadequate. ROW spending is generally correlated with overall levels of investment in other investment categories in this sub-program, particularly with targeted circuit improvement categories. The Company's projected increased investment in those other investment categories is driving increased test year projections for ROW procurement in the instant case.

LVD Lines Reliability: Overall Investment and Benefits

Q. What is the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines Reliability subprogram?

A. The Company is projecting LVD Lines Reliability capital expenditures of $180,763,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 7, column (k), and $312,886,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 7, column (l). The Company's historical actual spending in the LVD Lines Reliability subprogram, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 7, and below in Figure 34.

FIGURE 34
LVD LINES RELIABILITY SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$33,257	$39,451	$50,631	$34,935	$64,254	$180,763	$312,886

Q. How will the projected LVD Lines Reliability expenditures support the Reliability Roadmap?

A. The increased LVD Lines Reliability expenditures outlined in this case are critical for the Resilient Grid Plan that is defined in the Reliability Roadmap. The large increases in investment in this subprogram are mostly driven by increased investments in zonal health improvements and pole replacements. As the Reliability Roadmap makes clear, significant investment is needed in improving LVD zonal health and replacing LVD poles to deliver better reliability for customers, while managing the challenges of increasingly severe weather. With projected benefits provided by investments in the Company's targeted zonal improvements, which substantially reduce outages, and in ATR Loops, which can completely mitigate customer outages, these investments are necessary to achieve the Company's glidepath for reducing SAIDI.

Increased investment in this subprogram is also being driven by new investments in voltage conversions and open-wire secondary conversions to multiplex which will

deliver other non-reliability benefits to customers, particularly in vulnerable communities. In the bridge period and test year, there are over 35 miles of open-wire secondary conversions and 20 miles of zonal health improvements identified on circuits serving vulnerable communities.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this subprogram will be allocated across the four investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 35 below.

FIGURE 35

LVD LINES RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Targeted Circuit Improvement *strategies:*				
• Zonal Health Improvements	$61,320,000	497*	$34,917,000	175*
• Secondary	$19,680,000	66	$14,670,000	49
• Voltage Conversions	$8,427,000	44	$33,115,000	283
• Underground Cable Rejuvenation	$27,909,000	68	$65,989,000	158
ATR Loops	~~$17,539,000~~ $25,616,000	~~39~~ 59	~~$22,299,000~~ $15,412,000	~~40~~ 33
Pole Replacements	$29,711,000	3,076	$127,500,000	12,500
Circuit Exit Projects	$1,911,000	84	$3,616,000	197
Right-of-way	$6,188,000		$17,667,000	
Total	**$180,763,000**		**$312,886,000**	

*Units for Zonal Health Improvements represent total number of projects; individual projects have varying types of units as shown in Exhibits A-166 (JMP-1) and A-167 (JMP-2).

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Lines Reliability subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-166 (JMP-1), pages 2 through 14, and for the test year, listed in Exhibit A-167 (JMP-2), pages 2 through 10. The Company determined the projected costs of the projects in these exhibits based on the specific work scope for each project and historical costs of materials and labor from similar projects. These exhibits also identify the location and benefits of the projects.

Q. Can you provide further explanation regarding the "units" columns in Figure 34 above for zonal health improvements?

A. Zonal health improvements involve multiple types of projects, and it is difficult to summarize them with a single kind of unit in this figure. Some zonal health improvement projects involve addressing a certain number of line miles on a circuit, while others involve installing a certain number of fuses, and for some the applicable unit is simply "1 project." These details are reflected in Exhibits A-166 (JMP-1) and A-167 (JMP-2). Figure 34 simply lists the total number of line items for zonal health improvements in those exhibits.

Q. What are the different types of pole replacement projects listed in Exhibits A-166 (JMP-1) and A-167 (JMP-2)?

A. As discussed above, the Company has two different types of pole replacement work: projects to replace poles identified in prior years' inspections, and projects to replace poles identified during the Company's new groundline inspection program. In Exhibit A-166 (JMP-1), page 2, the Company has listed a number of pole replacement projects of the first type. Additionally, Exhibit A-166 (JMP-1), page 2, line 21, indicates that the Company projects to replace 1,700 poles in response to groundline inspections during the bridge

period. Exhibit A-167 (JMP-2), page 6, line 24, indicates that the Company projects to replace 12,750 poles in the test year in response to groundline inspections.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Lines Reliability subprogram?

A. LVD Lines Reliability projects form a critical part of the Company's glidepath for improving SAIDI as part of the Resilient Grid Plan, as described in the Reliability Roadmap, and by Company witness Kelly's testimony. In addition to driving system wide SAIDI improvements, LVD Lines Reliability projects consistently provide immediate benefits on the circuits or zones in which they are completed. The benefits for bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-166 (JMP-1), pages 2 through 14, and A-167 (JMP-2), pages 2 through 10. Types of benefits identified on the exhibits, and summarized in Figure 36, include:

- Customer-outage-minutes avoided – as defined previously, this is the expected reduction in the amount of outage time a group of customers would experience once the project is complete;
- Customers impacted – defines the number of customers benefiting from a project that improves voltage to ensure it remains within specifications for normal conditions; and
- Increase Safety by Installing Isolation Point at Sub – these isolation points installed just outside of the substation provide LVD line workers a visual open that they can operate to safely work on the circuit.

FIGURE 36
LVD LINES RELIABILITY BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	382,538,000	36,180,590
Customers impacted	16,103	43,850
Increase Safety by Installing Isolation Point at Sub	84	197

Q. What are the historical unit costs for each of the LVD Lines Reliability investment categories?

A. Historical unit costs for three investment categories are provided in Figure 37. There are no unit costs for the ROW investment category because units are not identified for this work.

FIGURE 37
LVD LINES RELIABILITY INVESTMENT CATEGORY UNIT COSTS

Investment Categories	2020	2021	2022	2023	2024
Targeted circuit improvements	$108,488 /project	$112,093 /project	$3,986 /project	$3,498 /project	$35,315 /project
Pole replacements	$8,357 /pole	$10,047 /pole	$14,738 /pole	$13,831 /pole	$5,758 /~~project~~ pole
Circuit exit enhancements	$33,696 /project	$43,658 /project	$51,993 /project	$46,842 /project	$31,147 /project
ATR Loops	$571,778 /loop	$668,319 /loop	$440,805 /loop	$462,945 /loop	$423,990 /loop

Q. Please explain any variation in unit costs over time.

A. Pole replacement unit costs increased in 2021 because Consumers Energy increased the standard for pole class size for added reliability, added resiliency, and to align with industry best practices. Increasing the Company's standard pole class size provides additional strength to the system for projects taking place across the electric service territory. Pole replacements take on average three to four hours to replace.

Replacement with increased sized poles, as part of upgrading to a higher pole class as discussed above, helps prevent the pole from breaking during an event such as a tree falling on the line. In the situation with a tree falling on a line, other weaker components will fail such as crossarms, braces, etc. The repair time for pole top components such as insulators and crossarms is substantially less than replacement of a pole that requires MISS

DIG notification and associated wait periods. The increase in pole class size impacts the cost of the pole ranging from $50 to $250 depending on class and height. Individual projects for targeted circuit improvements can vary widely in cost, based on specific project conditions and size of the projects, and as a result, the per-unit average cost can also vary. The lateral fuse addition projects completed in 2022 and 2023 each had a significantly lower cost than prior years' targeted circuit improvement projects. Accordingly, the unit cost for 2022 and 2023 for this investment category is less than prior years and less than in 2024. The unit cost for ATR Loops for 2022 and 2023 was lower than prior years because the Company completed some upgrades of existing loops, which have a lower cost, and focused its efforts on identifying lower cost loop projects. These lower cost loops avoided major LVD line upgrades for the new loops while maximizing benefit-cost ratios.

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. No. Average unit cost is not a good measure of spend to predict the cost of an individual project in this subprogram. There is a wide variance in work required ranging from $2,000 to as high as $3,000,000 or more per project. The Company builds a project plan for each year for this subprogram to achieve the reliability improvements needed for the LVD system and bases its investment levels on the cost of those projects.

LVD Repetitive Outages

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Repetitive Outages subprogram.

A. The LVD Repetitive Outages subprogram is similar to the LVD Lines Reliability subprogram in the types of work performed and in how projects are identified. However,

the LVD Repetitive Outages subprogram is designed to specifically address areas of the distribution system that consistently experience recurring customer interruptions, measured by the CEMI index, inclusive of MEDs. CEMI measures how many customers have experienced more than a given number of interruptions in a particular year. Investments in this program address issues of frequent interruptions primarily by targeting specific zones for improvements.

The LVD Repetitive Outages subprogram is affected by the current version of the Commission's Service Quality and Reliability Standards from Case No. U-20629 that went into effect on April 10, 2023. Those standards specify that utility performance is unacceptable if more than 6% of customers have four or more outages in a calendar year (CEMI-4+), and they also establish new bill credit rules for customers with too-frequent outages. In 2024, 10.9% of the Company's customers experienced four or more outages. In its final Order in Case No. U-21585, the Commission noted that the Company's 2023 performance on CEMI-4+ was too high, which warranted the Company's planned investment in this sub-program. When considering the 2024 CEMI-4+ results as well, it is clear to the Company that it must dedicate more focus to this sub-program in order to bring CEMI-4+ levels down to a more acceptable level. Additionally, the Commission has added a CEMI metric to its new financial incentives and disincentives mechanism in Case No. U-21400, providing further guidance that the Company must strive to address CEMI.

In order to meet the Commission's standards and expectations, increased investment is needed for preventing repetitive outages.

Q. How does the Company plan to address this concern?

A. The Company plans to increase investment in the Repetitive Outages sub-program to ensure it will achieve the Service Quality and Reliability Standard of 6% in the future. As described by Company witness Kelly, the Company is projecting a CEMI-4 of 8.2% in 2026 based upon the overall investment plan as approved by the Commission in Case No. U-21585. The Company needs to spend an additional $33.2 million in 2026 and $23.0 million in 2027 to achieve the standard beyond 2026, which is reflected in the Company's projected bridge period and test year investment levels in the instant case.

Q. How did the Company determine the needed scale of increased investment?

A. On average, it requires $90,000 in investment to improve a zone that impacts 118 customers with repetitive outages. To mitigate repetitive outages for each 1% of customers for which CEMI performance is short of the Commission's standard, the Company will have to address 161 zones at the cost of $14.45 million.

Q. What kinds of improvements are made for targeted zones in the Repetitive Outages sub-program?

A. Different solutions are considered depending on the specific conditions of the area being targeted. Depending on specific circuit conditions and attributes, typical investments include:

- System protection upgrades (e.g., fuses, switches, reclosers), using devices that maintain continuity of service by segmenting the electric distribution system into smaller sections, minimizing the number of customers affected by any individual outage;
- Replacing deteriorated or non-standard equipment such as poles, cross-arms, conductor, pins and insulators, lightning arrestors, non-standard equipment, and cutouts;
- Relocating portions of lines from dense tree or other poor access conditions for reduced tree interruptions and improved restoration time;

- Upgrading conductors that are at risk of contact with trees, typically in heavily wooded areas, to tree wire or aerial spacer cable to provide better tree protection, because both aerial spacer cable and tree wire are insulated wires that mitigate contact with trees and therefore associated interruptions; and

- Relocating portions of overhead lines underground to reduce tree-related and severe weather interruptions.

Q. How does work in the LVD Repetitive Outages subprogram connect to the plans outlined in the Reliability Roadmap?

A. Work in the LVD Repetitive Outages subprogram is similar in nature to that in the LVD Lines Reliability subprogram, so the discussion is closely related to the Zonal Health Improvements component of the Reliability Roadmap. As established in the Reliability Roadmap, the Company is planning an increase in its LVD Zonal Health Investment Plan to make these circuit health improvements. While this increase primarily affects the LVD Lines Reliability subprogram, work in the LVD Repetitive Outages subprogram also supports the goal of addressing zones in poor health, in addition to its primary goal of addressing customers with high CEMI.

Q. Do the investments included in the repetitive outages subprogram also help support SAIFI improvements, as described in the Reliability Roadmap?

A. Yes. There is a correlation between SAIFI, including MEDs, and the MPSC's CEMI performance standard, which does include storms. Company witness Kelly, in the Historical System Performance section of his testimony, provides a forecast of SAIFI, including MEDs, and CEMI. To improve customer satisfaction, the Company continues to focus on sustained SAIFI performance to assist in meeting the Repetitive Outage performance standard. An improving SAIFI metric increases the probability that the CEMI-4+ metric will be met. By targeting investment to the worst performing areas of the

distribution system, the Company expects to improve SAIDI, SAIFI, and CEMI. This reduces outage length and the frequency of outages experienced by customers.

The proactive investments made to replace deteriorated assets and reduce customer exposure to outages improve employee and public safety. Furthermore, investments in the LVD Repetitive Outages subprogram reduce overall costs associated with emergent response for additional interruptions in the capital subprogram LVD Lines Demand Failures. The benefits for bridge period projects are identified in the Benefit Type and Benefit columns of Exhibit A-166 (JMP-1), pages 23 through 27 and Exhibit A-167 (JMP-2), pages 11 through 16 are consolidated into Figure 38 below. Types of benefits identified on the exhibit and shown below include customer-outage-minutes avoided. As defined previously, this is the expected reduction in the amount of outage time a group of customers would experience once the project is complete.

FIGURE 38
REPETITIVE OUTAGE BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	14,678,557	13,307,890

Q. How does the Company identify LVD Repetitive Outages projects?

A. RAE data, as discussed previously in the LVD Lines Reliability section of my direct testimony, is the primary input in deciding where to invest for repetitive outages. One RAE output is a monthly zonal analysis report, which is reviewed by each area's LVD circuit planner. The report is broken down to identify specific zones, showing the number of customers that experience repetitive outages in each zone of the circuit. By focusing on areas where customers are likely to experience four or more interruptions annually, the Company can develop projects that have the greatest reliability benefit for the highest

number of customers first. To do this, the Company identifies zones with a high consistency ranking—a part of the zonal score illustrated in Figure 19—and a total reliability ranking below the threshold that would otherwise initiate a targeted circuit improvement project in the LVD Lines Reliability subprogram. These zones are likely to continue to experience interruptions, tend to have a smaller number of customers affected, are typically farther away from the circuit source, and thus contribute significantly to CEMI. Addressing these zones with Repetitive Outage projects may not produce the same total customer minute savings as targeted circuit improvement projects but will meaningfully improve CEMI.

The Company also uses feedback from field operations to identify areas that may also be creating outage concerns. This is then compared to the RAE and zonal report data to pinpoint the causes as described previously.

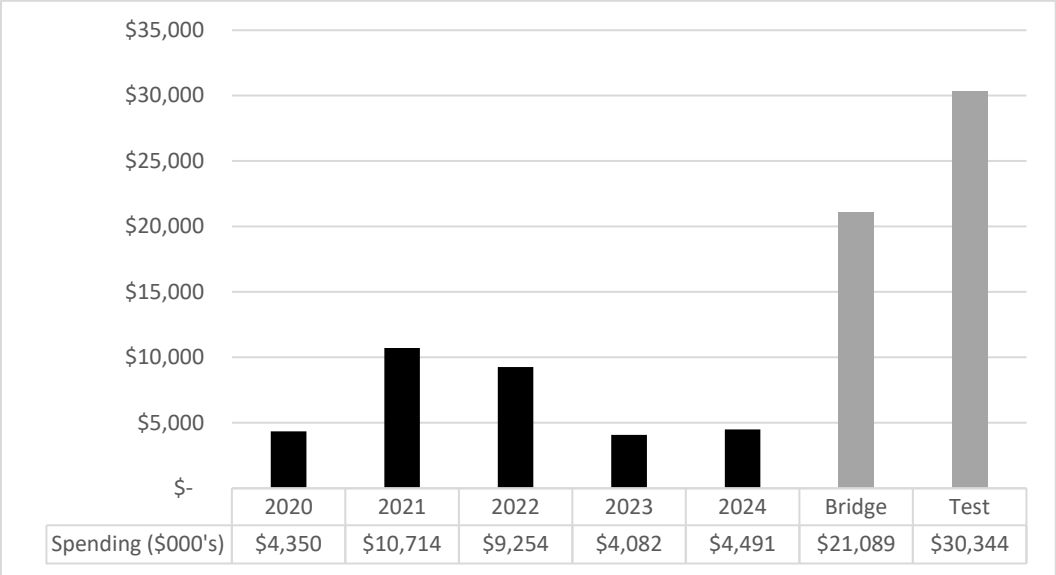
In addition to using RAE data, the Company focuses on customers experiencing CEMI-4+ and prioritizes them for projects in this subprogram, even if they might not have otherwise been considered for investment prioritization in the LVD Lines Reliability subprogram.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Repetitive Outages subprogram?

A. The Company is projecting LVD Repetitive Outages capital expenditures of $21,089,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 12, column (k), and $30,344,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 12, column (l). The Company is planning to complete 246 projects in the bridge period and 337 projects in the test year. The Company's historical actual spending in the LVD Repetitive Outages

subprogram, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 12, and below in Figure 39.

FIGURE 39
LVD REPETITIVE OUTAGES SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$4,350	$10,714	$9,254	$4,082	$4,491	$21,089	$30,344

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Repetitive Outages subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-166 (JMP-1), pages 23 through 27 and Exhibit A-167 (JMP-2), pages 11 through 16. The Company developed the projected costs of the projects in the exhibit considering typical costs for materials and labor, and the Company's previous experience performing similar projects. This exhibit also identifies the location and benefits of the projects. While projects for the bridge period have been identified and listed for this subprogram, the Company will continue to evaluate areas on the system, developing solutions for those areas following the process described below, and potentially reprioritizing work based on these evaluations.

Unit costs are higher in the bridge period and test year in this case than historical averages. The Company recognizes that CEMI performance is not improving significantly,

even as it addresses anomalies identified in inspections and completes lateral fusing within other subprograms. Therefore, the Company is shifting investments within this subprogram to focus on more robust, and more expensive, hardening projects such as line relocation, undergrounding, and replacing bare wire with tree resistant wire.

Q. Please explain the year-over-year variation in spending in this subprogram.

A. Overall investment in this subprogram was lower in 2023 than in earlier years as the Company focused on addressing anomalies identified during inspections, targeted zone projects, and overhead to underground relocation projects. Shifting investment from Repetitive Outages to LVD Lines Reliability and LVD Resiliency accomplishes the same goal of reducing SAIDI and CEMI. Investment levels increased modestly from 2023 to 2024. The purpose of increasing investment in this case from 2024 levels is to reduce the number of repeat outages a customer experiences once poor performance is identified, even if the SAIDI benefit would not prioritize the project in LVD Lines Reliability.

Q. In its final Order in Case No. U-21585, the Commission directed the Company to show that these dollars were spent on addressing reliability in LVD repetitive outages in this sub-program. What are you presenting in response to this direction?

A. Please refer to Exhibit A-169 (JMP-4). This exhibit identifies all of the projects in the LVD Repetitive Outages sub-program that had substantive investment in 2023 and/or 2024, and shows how many outages occurred both before and after work was completed. In reviewing this exhibit, it is important to note that the total dollars for each year does not exactly match the historical investment levels shown in Exhibit A-113 (MPK-3). In a given year, all sub-programs include some costs and some accounting credits related to closing

out prior year projects. As noted above, the purpose of Exhibit A-169 (JMP-4) is to show projects that had substantive investment in the years in question.

As has already been stated, the Company did invest less in LVD Repetitive Outages in 2023 and 2024 than in some other recent years, for reasons already discussed. However, the money that was invested in LVD Repetitive Outages in those years did go toward repetitive outage projects.

Q. What benefits will customers see from continued investment in the LVD Repetitive Outages subprogram?

A. Continued investment in the LVD Repetitive Outage subprogram, at the projected levels, is necessary for the Company to address customers with high CEMI and for the Company to meet the Commission's CEMI-4+ standard.

LVD Lines Rehabilitation

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Lines Rehabilitation subprogram.

A. The LVD Lines Rehabilitation subprogram includes capital repair or replacement of LVD lines equipment that has not actually failed but has been assessed to be at risk of failure in the near term. This subprogram consists of four investment categories:

(i) imminent rehabilitation;

(ii) meter voltage anomalies;

(iii) subsurface transformer replacements; and

(iv) modem replacement program.

Q. Are any of these investment categories new in recent years?

A. Yes. Subsurface transformer replacements was a new investment category in Case No. U-21585. It represents work that was newly prioritized during the asset health analysis that informed the 2023 Reliability Roadmap. Additionally, the meter voltage anomalies investment category is being newly defined in the instant case, based on voltage anomalies that the Company has recently begun to identify using its AMI. This effort was driven in part from the Commission's final Order in Case No. U-21389, directing the Company to continue identifying use cases for value-focused AMI metrics.

Q. Has this subprogram historically included any other investment categories?

A. Yes. Prior to 2024, this subprogram included an investment category called Security Assessment Repairs. As the Company initially explained in Case No. U-21389, that work will now be completed within the LVD Lines Demand Failures subprogram based on just P1 and P2 anomalies that are identified in inspections. If Priority 3 ("P3") or Priority 4 ("P4") anomalies are identified, they may be prioritized for action in the imminent rehabilitation investment category in this subprogram. Figure 40 presents the types of hazards classified as P3 and P4. The hazards are listed by the priority code for the anomaly.

FIGURE 40
LVD SECURITY ASSESSMENT HAZARD CODES

Code	Description
P3 - Failure Expected Before Next Inspection	
P3A	Broken Guy - Leaning Pole
P3B	Pole: Damaged
P4 - Heightened Risk of Failure	
P4A	Broken/Missing Cross-arm Braces
P4B	Broken Guy - Non-Leaning Pole
P4C	Damaged Equipment (Transformers, Reclosers, Etc.)
P4D	Lightning/Flashover Burn Marks
P4E	Poorly Sagged Line

Q. Please explain the imminent rehabilitation investment category.

A. The imminent rehabilitation category addresses issues that arise in which an actual failure has not occurred, but repair or replacement is required to prevent outages and the additional expenses associated with fixing following failure as opposed to doing planned, straight-time work with lower unit costs and higher efficiency. Imminent rehabilitation projects deal with conditions identified outside the Company's inspection cycles and normal planning work, but there is no immediate need for repair as there would be with LVD Lines Demand Failures projects. Imminent rehabilitation projects include:

- P3 and P4 conditions, as identified in Figure 40, may be addressed in this investment category, such as replacing poles with visible damage or deterioration identified outside of the inspection cycle by line crews or customers.

- Underground cable repair after a fault is isolated and customers are restored under service restoration activities. If this is the first time the section of line has faulted, the Company typically will expose the fault and splice it. If this section or area has experienced multiple faults or the vintage of the cable warrants replacement, the Company will develop a project to replace the faulted section of cable and, in some cases, adjacent sections of cable as well.

- Underground padmount equipment may require relocation or replacement due to ground shifting that causes leaning or sinking.

- Underground padmount equipment inspection replacement. Each year padmounted equipment is visually inspected around the exterior for any signs of oil leaking or holes that expose electrical components. When found, the equipment is replaced.

- Primary or secondary voltage improvements identified through customer complaints, power flow analyses, or line crew reports and include projects such as transformer replacement, conductor upgrades, load balancing, or voltage conditioning device installation such as capacitor banks or voltage regulators.

- Deteriorated conductor or equipment replacement, including replacement of secondary conductors that are losing the protective coating, severely rusting equipment, or any wear and tear on the conductor that requires replacement.

- Radio frequency interference projects requiring pole top component or other equipment replacements to resolve interference to communications, radios, and other devices as required by Federal Communications Commission rules.

- Clearance violations of conductor or equipment with respect to structures or the ground that are not an immediate risk requiring relocation, pole upgrades, or new pole installations.

Q. Please describe the general inputs that the Company uses to identify issues that must be addressed by the imminent rehabilitation investment category.

A. The Company collects data through its electric operations organization. For example, there may be locations that electric operations employees have frequently visited to restore service for a failed underground cable in the same subdivision. This team conveys this information to LVD circuit planners so they can investigate and create a project for a full replacement of the underground cable, and possibly live-front transformers or padmounted switching equipment in that subdivision, if necessary.

Q. Please explain the meter voltage anomalies investment category.

A. Rule 702 of the Commission's Standards of Quality of Services requires that the Company provide customers with voltage that is ±5% of nominal voltage. The Company is able to use its AMI for continuous monitoring of voltage at the service delivery point to customers, and from this the Company knows that over 99% of customers receive voltage at compliant levels. However, voltage anomalies do occur. When voltage is unacceptably low, this is typically due to heavily loaded secondary and line transformers. When voltage is moderately high (between 5% and 10% greater than nominal), this is typically due to voltage regulation device issues. When voltage is greater than 10% above nominal, this is typically due to internally-faulted line transformers that are still energized. The large majority of voltage anomalies fall in the second of these categories. Historically, the Company has fixed voltage anomalies as they are reported by customers on a reactive basis,

although in some cases a customer may not be aware if their voltage is too high or too low. Going forward, though, the Company plans to use its AMI data to proactively address voltage compliance concerns, and is therefore proposing to invest in correcting all three voltage anomaly causes, and will replace line transformers, mitigate regulator issues, and mitigate low voltage secondary issues. This is also discussed in the Reliability Roadmap.

Q. Please explain the modem replacement program investment category.

A. The Company has begun a project to replace cellular modems that are installed inside control devices (e.g., Capacitors and Line Voltage Regulators) throughout the LVD grid. The present vendor of the Company's cellular modems announced a cessation of manufacturing in 2020 and informed the Company that it will end support in 2029. An end of support announcement means that security patches, firmware updates, and hardware support/repair will no longer be available, which negatively impacts equipment reliability and security. The security patches protect the Company from external parties accessing the data and other cyber threats. Also, the equipment hardware will no longer be available, reducing or eliminating the capabilities enabled by automation and conservation voltage reduction ("CVR"). Due to the large quantity, geographic locations, and physical effort needed to replace each modem, it is imperative to begin replacement efforts prior to the end of support date. Over the course of the following years, the Company will replace the total population of 5,000 cellular modems, completing approximately 800 replacements per year.

Q. Please explain the subsurface transformer replacement investment category.

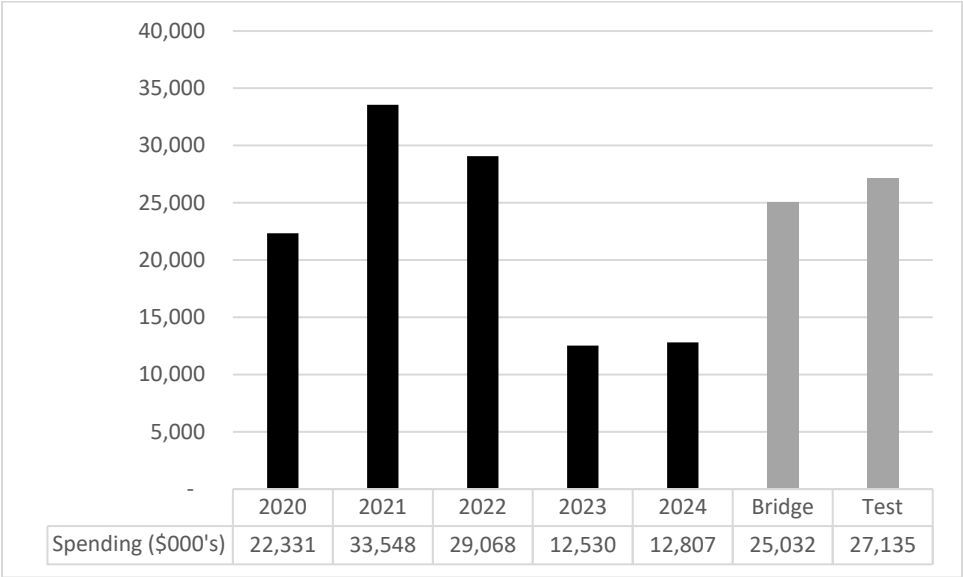
A. As discussed, starting on page 60 of the Reliability Roadmap, the Company's underground system has 159 of its original subsurface transformers still installed. These transformers

do not have a major impact on reliability but do pose a safety risk for Company employees and the public. Since they are underground, employees have difficulty accessing and repairing them when they fail, and their location makes it difficult for members of the public to recognize them and take care to avoid them. When subsurface transformers do fail, outages last approximately four times as long as during padmount transformer failures, given the difficulty of repair, and subsurface transformers are also prone to leaking subterranean oil. To address these risks, the Company plans to replace all subsurface transformers with padmount transformers by the end of 2027.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines Rehabilitation subprogram?

A. The Company is projecting LVD Lines Rehabilitation capital expenditures of $25,032,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 17, column (k), and $27,135,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 17, column (l). The Company's historical actual spending in the LVD Lines Rehabilitation subprogram, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 17, and below in Figure 41.

FIGURE 41
LVD LINES REHABILITATION SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	22,331	33,548	29,068	12,530	12,807	25,032	27,135

Q. How did the Company develop its projected expenditures in this subprogram?

A. While the Company now addresses security assessments in the LVD Lines Demand Failures sub-program (which led to lower investment levels in this sub-program in 2023 and 2024), the levels of investment for the bridge period and test year will continue to address system deterioration and the resulting anomalies identified on the system. The bridge period and test year also include the newer investment categories for modem replacements and subsurface transformer replacements as discussed, and the new investment category for meter voltage anomalies. The bridge period and test year spending amounts will enable the investment needed to complete the projects identified.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this subprogram will be allocated across the three investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and the test year for each investment category as identified in Figure 42.

FIGURE 42
LVD LINES REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Imminent rehabilitation	$15,120,000	442	$9,413,000	165
Subsurface transformers	$528,000	15	$3,181,000	54
Modem Replacement Program	$2,998,000	800	$2,988,000	800
Meter Voltage Anomalies	$6,386,000	N/A	$11,553,000	N/A
Total	**$25,032,000**		**$27,135,000**	

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Lines Rehabilitation subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-166 (JMP-1), pages 15 through 22, and for the test year, listed in Exhibit A-167 (JMP-2), pages 17 through 20. The Company developed the projected costs of the projects in these exhibits considering estimated costs for materials and labor and the Company's previous experience performing similar projects. These exhibits also identify the location and benefits of the projects. Note that the Company only creates orders for specific modems close to the time that they are replaced, so there are no specific projects listed for this investment category. Spending amounts are based on a continuation of the same volume of work going forward. Additionally, the Company does not have specific projects identified for meter voltage anomalies. The Company will identify specific proactive projects for this investment category closer to the time of project execution based on up-to-date AMI data; the projected work volume for meter voltage anomalies is based on the historical levels of anomalies visible in the AMI data. Finally, it is important to note that the Company only has five

total subsurface transformer projects in the test year, but this is due to one large project replacing many subsurface transformers in a subdivision.

Q. Please explain the year-over-year variation in spending in this subprogram.

A. In 2021, the Company addressed P3 and P4 deteriorated system assets identified in security assessments and imminent rehabilitation. That increase over 2020 enabled the completion of the circuits with previously completed security assessments. Material delivery challenges in 2022 inhibited work in other subprograms resulting in crews completing more imminent rehabilitation work which used materials that were more available.

Q. What benefits will customers realize through the Company completing work in the LVD Lines Rehabilitation subprogram?

A. The LVD Lines Rehabilitation subprogram addresses conditions that could result in interruptions to customers or present unacceptable system operating conditions and, therefore, provides a benefit to customers by reducing the likelihood of future actual failures. By replacing or rehabilitating equipment before it fails, work can be completed in a more economical manner by having the correct materials and resources in place before work begins. The approximate number of customers benefitting from known bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-166 (JMP-1), pages 15 through 22, and A-167 (JMP-2), pages 17 through 20.

Q. Please explain why some of the imminent rehabilitation projects in the LVD Lines Rehabilitation subprogram have similar customer benefits.

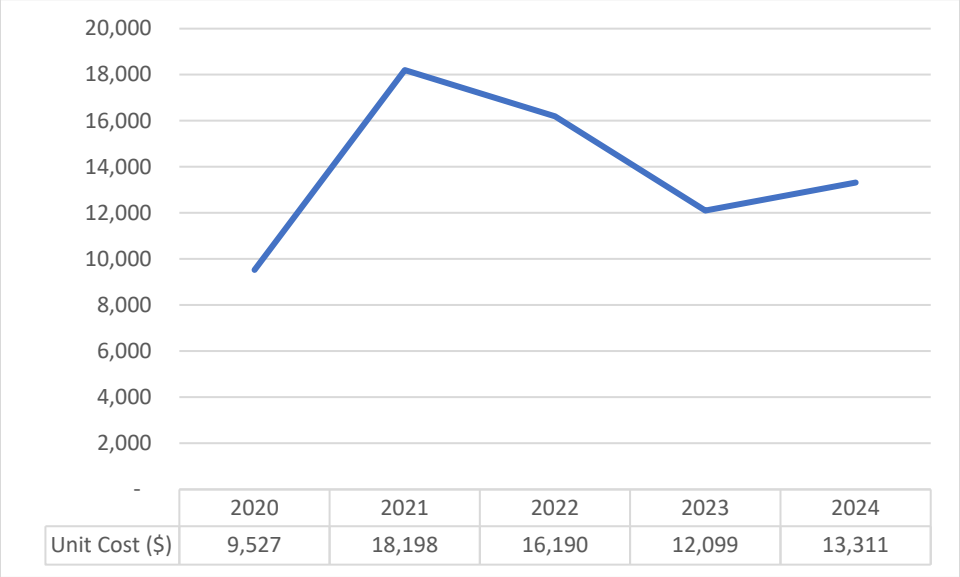
A. The work required for many of these projects is similar in nature and therefore some projects are estimated to have similar benefits based on the reported finding and historical orders of the same type. To improve secondary voltage for customers, it typically requires

new secondary conductor and a transformer with five customers receiving the benefit. When a pole is replaced for deterioration in this subprogram, on average it benefits 242 customers.

Q. What are the historical unit costs for the imminent rehabilitation projects in the LVD Lines Rehabilitation subprogram?

A. The historical unit costs are provided in Figure 43 below.

FIGURE 43
LVD LINES REHABILITATION INVESTMENT CATEGORY UNIT COSTS



	2020	2021	2022	2023	2024
Unit Cost ($)	9,527	18,198	16,190	12,099	13,311

Q. Please explain any variation in unit costs over time.

A. Imminent rehabilitation can vary due to variations in size and complexity of work orders. In 2019, projects considered deterioration were being charged to imminent rehabilitation. Primarily, this work included replacement of overhead or underground deteriorated primary and secondary conductors over multiple spans due to frequent wire downs. In 2020, these projects were redefined to be zonal health projects, as described in the LVD Lines Reliability portion of my testimony. In 2021 and 2022, the scope of the work required on imminent rehabilitation was more extensive than that required in other years.

For example, in 2021, more underground work was completed than overhead and there were more locations completed per order.

Q. Does an average unit cost accurately reflect the expected spend per project for this subprogram?

A. No. There is a wide variance among work required ranging from $1,000 to as high as $2,100,000 per project. However, because there is a reasonable volume of units an average unit cost could be used to analyze the projections for the overall subprogram, but not the cost of any individual project.

Resiliency

Q. What is the purpose of the Resiliency subprogram?

A. As described by Company witness Kelly and as discussed in the Reliability Roadmap, the Company's distribution objectives include building a system that is both reliable and resilient. While much of the overall Reliability Program is focused on improving reliability, this Resiliency subprogram has a particular focus on enhancing resiliency. It does this by proactively investing in strategic distribution system hardening to increase the distribution system's ability to withstand major storm events and recover from those events more quickly. As noted earlier in my direct testimony when introducing the Reliability Program, the primary purpose of Resiliency subprogram investments is to limit customer interruptions following major weather events, as opposed to solely improving blue-sky SAIDI (i.e., reliability primarily experienced during normal conditions).

Q. How does the focus of Resiliency subprogram investments compare with the Company's other investments in the Reliability Program?

A. The Company's other Reliability Program investments are primarily identified based on historical performance of portions of the system, with a focus on improving blue-sky reliability, measured in customer-outage-minutes. However, focusing only on normal weather reliability leaves parts of the system exposed to extreme weather events that result in long and costly outages and customer hardships.

Resiliency subprogram investments are meant to focus on prevention, recovery, and survivability, particularly during large events. Preventing outages is the ideal way to reduce the number of outages to customers. Each outage represents a unit of work that must be completed by line workers who at times must travel from states located significant distances from Michigan. If this can be avoided through prevention, the amount of time spent on restoring service following a major event is considerably reduced. Likewise, survivability increases the system's ability to withstand a storm system without failure. Finally, recovery improvements address those times when prevention and survivability are not enough, and the outage occurs. Investing in recovery reduces the duration of outages that do occur.

Q. Why does the Company have a standalone Resiliency subprogram?

A. The Company has experienced an increasing frequency of high-speed wind gusts in its service territory over the past several years which, along with system deterioration, have resulted in an increase in the amount and severity of electrical outage incidents. One of the recent events in August 2021 was a multi-day storm with 70 mile-per-hour wind gusts that resulted in interruption to 401,000 of the Company's customers, with restoration

lasting up to seven days. A subsequent storm in December 2021 had peak wind gusts of 79 miles per hour, interrupting more than 210,000 of the Company's customers, with restoration lasting up to four days. Furthermore, two ice storms in February 2023 interrupted approximately 400,000 customers, with restoration lasting up to eight days. These interruption events—which strain the distribution system beyond previously experienced levels—have increased the Company's focus on ways to mitigate major weather events and led to new proposals targeting resiliency in the Company's 2022 rate case in Case No. U-21224, which were further expanded in Case No. U-21389 in 2023. The Company's Reliability Roadmap takes projections of worsening climate into account and correspondingly calls for additional resiliency investments to harden the system and reduce customer outages even as the system faces more storms.

Q. How does the Resiliency subprogram align with the Reliability Roadmap?

A. The Reliability Roadmap is focused on both improving system reliability under normal operating conditions and improving resiliency under extreme conditions. In the Reliability Roadmap, the Company defines its strategy for LVD resiliency, based on a ramp-up of LVD overhead-to-underground conversions; continuing to invest in fractionalization; and continuing to install ATR loops. The Resiliency subprogram investments included in this case are tied to those laid out in the Reliability Roadmap.

Q. What projects, activities, and other types of work are included in the Resiliency subprogram?

A. Two primary investment categories are included in the Resiliency subprogram: Fractionalization and LVD Overhead to Underground conversions. The project list exhibits also include projects for the Vulnerable Communities Resiliency Plan that is

primarily discussed by Company witness Kelly, because these projects are primarily intended to increase resiliency in the targeted communities. The project list exhibits also include work related to underground services and make secondary improvements in disadvantaged communities ("DACs") under a grant from the Michigan Department of Environment, Great Lakes, and Energy ("EGLE"). While the Reliability Roadmap also discusses ATR Loops as a resiliency investment, they are included in the LVD Lines Reliability subprogram because they also provide a substantial blue-sky SAIDI benefit.

Fractionalization

Q. Please explain what projects will be enabled by expenditures in the Fractionalization investment category.

A. Fractionalization is the practice of segmenting LVD circuits into smaller sections with fewer customers to reduce the number of customers impacted by single contingency outages and customer exposure to outages. As the distribution system has been expanded over many years to meet the requirements of connecting new customers, there are a subset of circuits with disproportionately high customer counts and overhead line exposure, resulting in reliability and resiliency challenges due to the underlying system configuration. By investing in the Fractionalization investment category, the Company will be able to:

i. complete twelve new circuits at seven existing substations;

ii. complete one new substation with four new circuits; and

iii. complete purchase order milestone payments for one new mobile substation.

The mobile substation will support construction of the additional substation projects proposed in this subprogram, avoiding customer outages that would have otherwise been required.

FIGURE 44
FRACTIONALIZATION OF A SUBSTATION

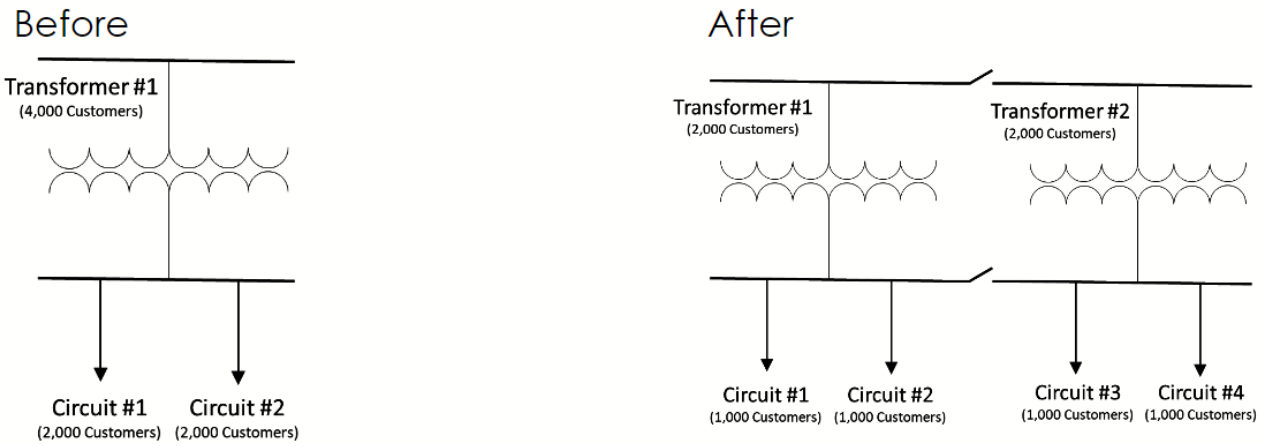
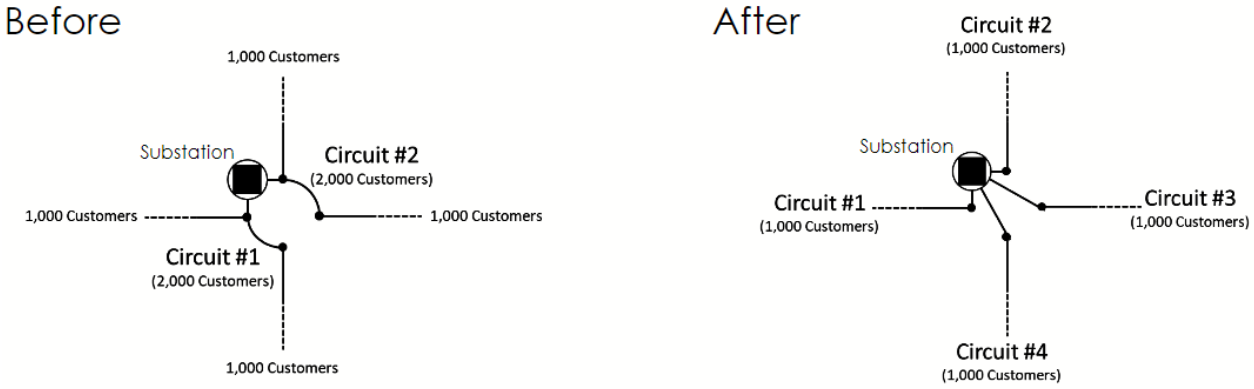


FIGURE 45
FRACTIONALIZATION OF LVD CIRCUITS



Q. What criteria are used to identify the projects for the Fractionalization investment category?

A. The Company is targeting circuits that fall into the top tiers of circuits based upon customer count and overhead line exposure. The top tiers of circuits serve more than 2,000 customers or more than 75 miles of overhead line exposure. As is shown in Figure 46 and Figure 47, there is a small percentage of circuits that are outliers with respect to customers served and miles of overhead line exposure.

FIGURE 46
CIRCUITS RANKED BY OVERHEAD PRIMARY LINE EXPOSURE

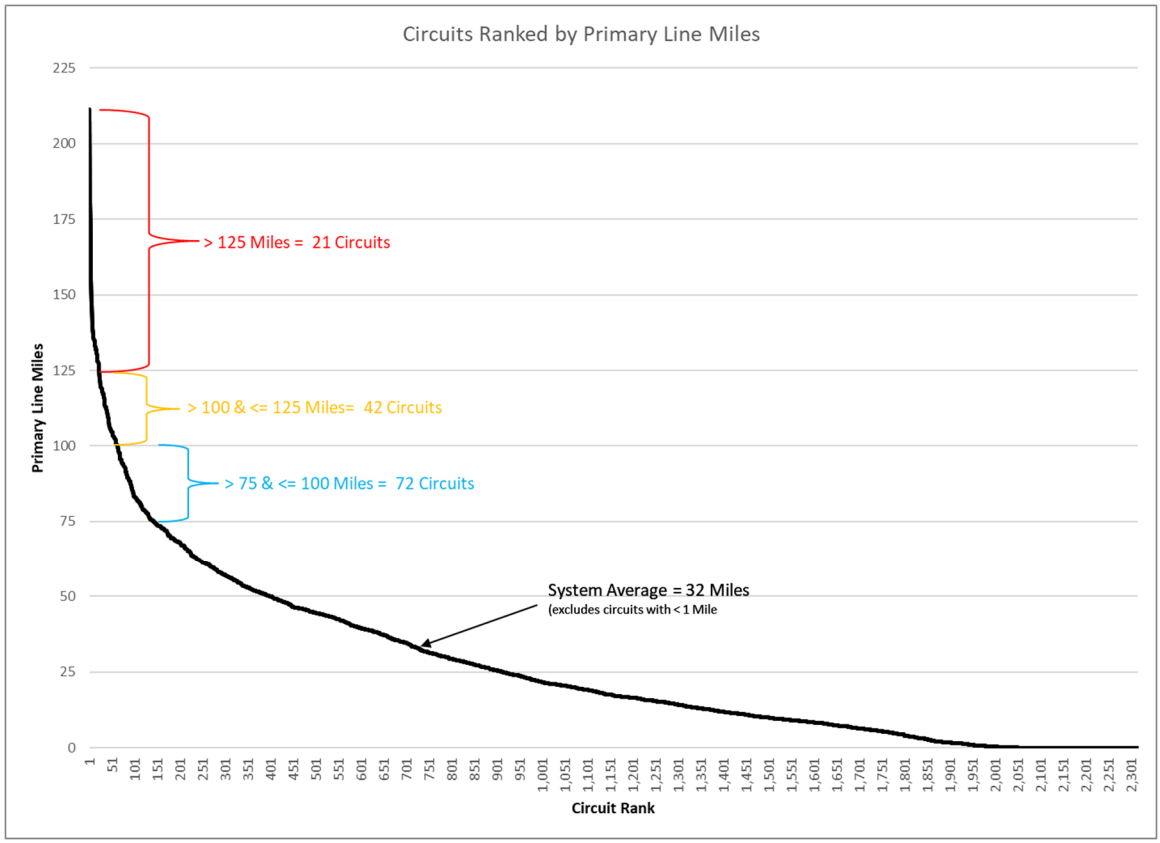
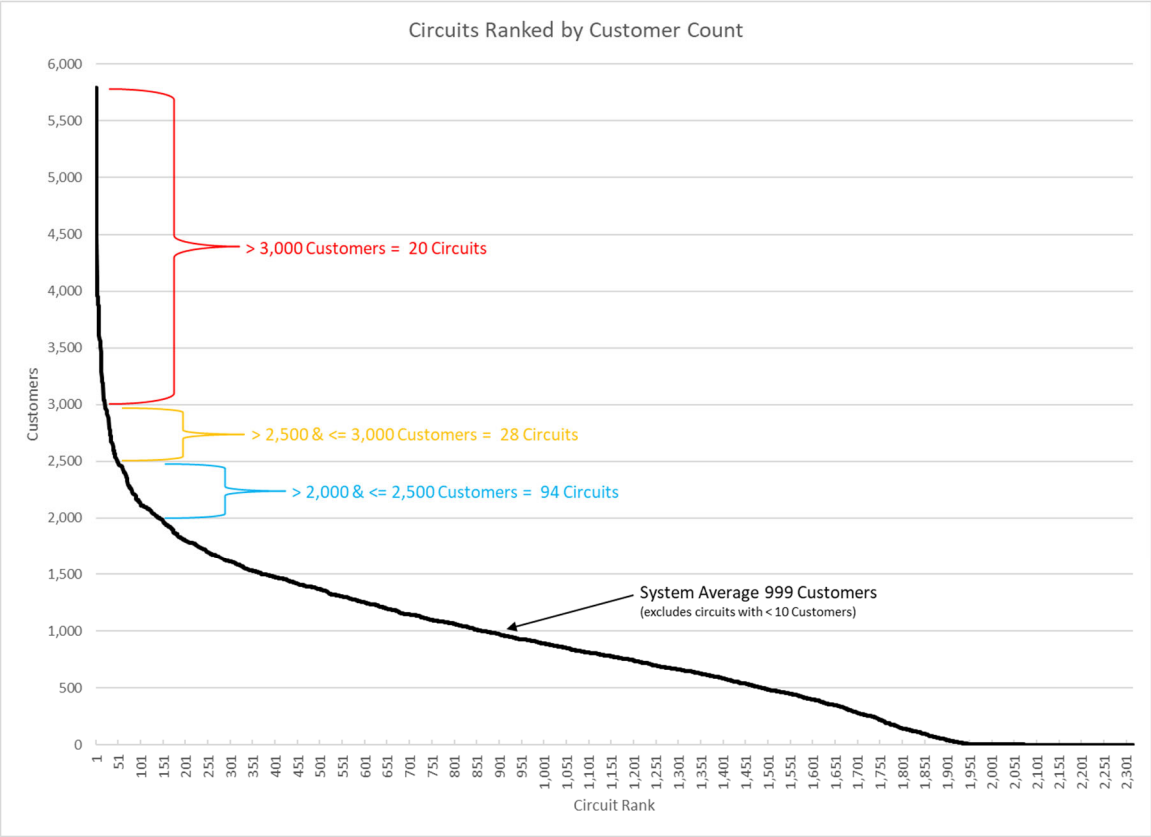


FIGURE 47
CIRCUITS RANKED BY CUSTOMER COUNT



Q. What has been the outage history for these top tiers of circuits?

A. For the years 2019 to 2023 combined, circuit outages impacting more than 2,000 customers or on circuits with more than 75 miles accounted for 848,539 customer interruptions and 402,278,560 customer-outage-minutes. Accordingly, these circuits can most benefit from Fractionalization and the improved resiliency it will provide.

Overhead to Underground Conversions

Q. Please explain what projects will be enabled by expenditures in the Overhead to Underground investment category.

A. The Overhead to Underground investment category will fund investments in LVD lines to completely replace certain sections of overhead LVD line with underground lines and associated equipment. This investment category will not fund undergrounding of services.

Q. Why does the Company plan to underground LVD lines?

A. During large storm events, the Company can become inundated with LVD overhead line failure incidents. In the February 2023 ice storms, the Company had approximately 10,000 reported wire downs. Experience has shown that many of these incidents are precipitated by storms blowing or breaking trees that then fall upon the LVD overhead lines, resulting in outages. The Company had similar issues with the ice storm that hit northern Michigan in March and April 2025. Targeting certain overhead lines to move underground will avoid outages on these lines caused by falling trees.

Q. What criteria was used to identify the projects for the Overhead to Underground investment category?

A. The Company has used the following selection criteria for this investment category. The selected zones of the LVD system will be single-phase; have had at least one outage in the last 24 months; serve between 10 and 200 customers; be operated at one of the three standard wye voltages; not be considered for another reliability project; have a load after installation of 36% or less of the ampacity of the newly installed facilities; and be located in an area that has experienced tree- or weather-related outages.

Q. Please further explain these criteria choices.

A. Single-phase was selected due to its lower cost, the typically limited number of customers who would be negatively impacted by an underground line outage, and being least susceptible to above average load growth. LVD protective zones with at least one outage in the last 24 months were selected so that there would be a more immediate reliability benefit. Limiting the customers served by the zone to between 10 and 200 ensures that the project provides benefits to more than a few customers, while limiting the impact of any outage on the underground facilities. Underground conversion of only the three standard wye voltages ensures that additional costs are neither initially incurred on the additional equipment to accommodate delta configurations nor the conversion cost to a standard wye voltage later. Similarly, selecting zones that are not considered for another reliability project avoids duplication of efforts. Ensuring that the new underground facilities are loaded to 36% or less of their ampacity provides for typical load growth without needing to replace the facility before end-of-life. Finally, underground conversions in areas that have experienced tree and weather-related outages helps to minimize future forestry clearing costs.

Q. Have any of the selection criteria changed since the Company's pilot as proposed in Case No. U-21389.

A. In the pilot in Case No. U-21389, the Company selected zones serving between 10 and 100 customers, but the upper limit has been increased to 200 customers. The pilot also focused on zones with CAIDI of over 600, and this constraint has been removed. Additionally, the pilot focused on zones with dense tree cover; as noted above, this criterion has been

redefined to focus on zones that have recently experienced significant tree and weather-related outages.

Furthermore, as discussed by Company witness Kelly, the pilot determined that undergrounding projects would have higher costs when in densely populated areas or areas that require significant boring work, and lower costs in more lightly populated areas where trenching or plowing is possible. The Company's projects in the instant case were identified based on being able to take advantage of locations that would have lower unit costs based on these lessons learned.

Q. Do these selection criteria mean that all circuits or zones meeting these selection criteria will ultimately be converted to underground?

A. No, not necessarily. The purpose of the selection criteria is to narrow the Company's total population of LVD circuits down to a more manageable list so that it can identify locations where undergrounding is most justified. In the instant case, the Company is only seeking cost recovery related to the projects identified in Exhibits A-166 (JMP-1) and A-167 (JMP-2).

Resiliency: Overall Investment and Benefits

Q. What is the Company's projected test year spending level, for which it is requesting cost recovery for the Resiliency subprogram?

A. The Company is requesting recovery of additional resiliency capital expenditures in the amount of $21,194,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 20, column (k), and $35,765,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 20, column (l).

Q. Please explain how the capital expenditures projected for the test year for this subprogram will be allocated across the two investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 48 below.

FIGURE 48
RESILIENCY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Fractionalization	$15,826,000	8	$11,647,000	3
Overhead to Underground	$1,250,000	1.4	$20,000,000	50
EGLE - MIEJ Undergrounding Secondary and Services	$4,118,000	7	$4,118,000	9
Total	**$21,194,000**		**$35,765,000**	

Q. Please identify the projects that will be completed in the Resiliency subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-166 (JMP-1), page 28, and for the test year, listed in Exhibit A-167 (JMP-2), page 21. Projected project costs were developed considering estimated costs for materials and labor and the Company's previous experience performing similar projects. This exhibit also identifies the location and benefits of the projects.

Q. Are there any projects that span multiple years?

A. Yes. The Backus, Greenwood, and Mobile 27 projects, listed in Exhibit A-166 (JMP-1), page 28, lines 2 through 4, will span multiple years due to mobile substation purchase order milestone payments and construction scheduling. The Eagle and Mobile 27 projects, listed

in Exhibit A-167 (JMP-2), page 21, lines 30 and 31, will span multiple years due to mobile substation purchase order milestone payments and construction scheduling.

Q. How were the proposed Fractionalization projects identified?

A. The proposed Fractionalization projects will address four of the 40 highest customer count circuits, and four of the 40 highest line exposure circuits. Figure 49 identifies the pre-investment and post-investment configurations for these circuits benefitting more than 28,000 customers. Additional projects shown in Exhibit A-167 (JMP-2) will also address circuits with over 2,000 customers or with line exposures over 75 miles of exposure.

FIGURE 49
FRACTIONALIZATION PROJECTS STATISTICS

Resiliency Projects	Pre-Investment Configuration				Post-Investment Configuration (Estimate)				Benefit
	Substation	Circuit	Customers	Total Miles	Substation	Circuit	Customers	Total Miles	Cust-Min
Backus Substation	Backus	Springbrook	5,587	116	Backus	Springbrook	3,564	74	217,331
	Backus	Maple Valley	1,001	60	Backus	Maple Valley	1,001	60	
					Backus	New Circuit 3	1,250	27	
					Backus	New Circuit 4	773	15	
Bennington Substation	Bennington	Manitou	759	53	Bennington	Manitou	759	53	76,750
	Bennington	Grand River	1,390	114	Bennington	Grand River	852	63	
					Bennington	New Circuit 3	538	51	
Eagle Substation	Chicago	Chicago	1892	28	Chicago	Chicago	1,892	28.077	249,309
	Chicago	Pinebrook	2650	33	Chicago	Pinebrook	1,987	25.161	
	Hager Park	Wellington	948	31	Hager Park	Wellington	553	13.885	
	Hager Park	Hager Park	3,735	58	Hager Park	Hager Park	968	31.701	
	Rosewood	Pioneer	1,171	13	Rosewood	Pioneer	1,171	12.681	
	Rosewood	Cottonwood	2,083	22	Rosewood	Cottonwood	2,083	21.844	
	Rosewood	Lamplighter	2,241	24	Rosewood	Lamplighter	1,923	20.302	
	Van Buren	Van Buren	1,871	25	Van Buren	Van Buren	1,316	17.27	
	Van Buren	Moss Lake	375	10	Van Buren	Moss Lake	375	9.58	
	Van Buren	Rush Lake	1,516	36	Van Buren	Rush Lake	680	20.943	
					Eagle	New Circuit 1	1,610	24.272	
					Eagle	New Circuit 2	1,051	16.462	
					Eagle	New Circuit 3	1,838	21.407	
					Eagle	New Circuit 4	1,035	14.923	
Greenwood Substation	Alger	Skidway	4,093	131	Alger	Skidway	613	60	361,337
	Alger	Forest Lake	1,647	117	Alger	Forest Lake	1,034	58	
	Greenwood	Rau Road	1,055	87	Greenwood	Rau Road	912	87	
	Greenwood	Indian Lake	1,240	95	Greenwood	Indian Lake	1,240	83	
					Greenwood	New Circuit 3	4,236	142	
Whittemore Substation	Whittemore	M-65	1,654	135	Whittemore	M-65	723	64	107,599
	Whittemore	Sand Lake	2,300	87	Whittemore	Sand Lake	1,907	48	
					Whittemore	New Circuit 3	457	40	
					Whittemore	New Circuit 4	867	70	

Q. Why does the projected investment level for Overhead to Underground vary between the bridge period and the test year?

A. In Case No. U-21389, the Commission approved approximately ten miles of undergrounding projects as part of a proposed pilot. In Case No. U-21585, the Company proposed to expand that pilot and continue undergrounding additional circuits, but the Commission did not approve this proposal since pilot results were not yet available. Because of this, the Company is not doing any new major undergrounding work in the bridge period in this case. The projects included in the bridge period consist of one project that was approved as part of the pilot in Case No. U-21389 that is still being finished in the bridge period ("TAWAS/TAWAS/482"). It also includes one project ("SQUIRE HILL/EDGEWATER/775") that was proposed in Case No. U-21585. The Company started work on this project at the beginning of March 2025, coincident with the test year in Case No. U-21585, before the Commission issued its final Order in that case. Because the Company had already commenced work, and because the project serves a vulnerable community, the Company will complete this work in the bridge period to deliver benefits to these customers.

As Company witness Kelly discusses, the Company now has the results of the pilot, has assessed those results, and now plans to move forward with further undergrounding work beginning in the test year. Exhibit A-167 (JMP-2), page 21, lists these new undergrounding projects.

Q. What is included in the projects in Exhibits A-166 (JMP-1) and A-167 (JMP-2) related to "undergrounding of services and secondary improvements in DACs?"

A. The Company received a grant from EGLE under Section 40101(d) of the Infrastructure Investment and Jobs Act, that is intended to underground secondary in disadvantaged communities, and these projects are where the Company will execute this work. Note that this work is separate from overhead to underground conversions, which focus on primary circuits, not on secondary.

Q. What is included in the projects in Exhibit A-167 (JMP-2), page 22, related to "Resiliency – MIEJ Hardening?"

A. These projects represent the test year work for the Company's Vulnerable Communities Resiliency Plan, as discussed in detail by Company witness Kelly.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Resiliency subprogram?

A. The additional resiliency spending will provide direct and immediate reliability benefits to customers connected to the projects. These projects will better prepare the LVD system for the increasing frequency and severity of wind gusts and storms. The LVD system is most at risk of experiencing failures from severe weather. Therefore, the resiliency spending will reduce the quantity of outages or the extent of the LVD system impacted during an outage.

Q. How will the identified Fractionalization projects improve resiliency?

A. Fractionalization will address recovery and prevention by dividing the system into smaller portions, reducing the number of customers experiencing an outage for a single failure; and

reducing the customers' miles of exposure to overhead line outages, preventing outages to customers that would have otherwise been interrupted.

Fractionalization will also provide operational switching opportunities, allowing for improved fault isolation and faster restoration of customers prior to the completion of repairs, also enabling a quicker recovery from the outage. An ancillary benefit of Fractionalization is increased system capacity, available for both increased load and renewable resource hosting capacity.

Q. How will the identified Overhead to Underground projects improve resiliency?

A. Investing in conversion of LVD overhead lines to underground will increase both survivability and prevention. Underground LVD lines are expected to survive nearly all tree-caused and ice-caused failures preventing outages during major storm events. The Company's experience has shown that the greatest cause of interruptions on the LVD system is due to trees. Winter storms with ice also cause outages during major events. EPRI research and the WEC Energy Group have found that undergrounding of single-phase laterals is highly effective at hardening the distribution grid from storm damage and reducing interruptions.

The picture in Figure 50 provides an example of the types of incidents that can be avoided if lines are placed underground. In this instance, a tree has fallen on the line in an area that will be difficult for crews to reach, because it is located in the woods with snow cover.

FIGURE 50
TREE ON OVERHEAD SINGLE-PHASE PRIMARY LINE



Q. Please summarize the benefits customers will realize through the Company completing work, at the requested spending level, in the Resiliency subprogram.

A. With fewer line miles for line workers to patrol and repair to restore service due to fractionalization and with fewer LVD line failures overall due to overhead-to-underground conversions, there will be less restoration work time required, providing more time for line workers to complete other restoration work, resulting in a quicker restoration overall. Simply put, faster restoration and recovery from an event result in shorter electric interruption durations, benefiting all storm-impacted customers.

The direct customer benefits for the projects are identified in the Benefit Type and Benefit columns of Exhibits A-166 (JMP-1), page 28, and A-167 (JMP-2), page 21. Types of benefits identified on the exhibits, and summarized in Figure 51, include:

FIGURE 51
RESILIENCY BENEFITS SUMMARY

Investment Category	Benefit Categories	Bridge Period	Test Year
Fractionalization	Customer-outage-minutes avoided	1,214,132	76,750
Overhead to Underground	Customer-outage-minutes avoided	-	2,040,235
EGLE - MIEJ Undergrounding Secondary and Services	Customers	193	179

Capacity Program

Q. What portion of the Capacity Program will your testimony discuss?

A. The Capacity Program is designed to ensure the distribution system can serve the electric peak demand, keep the system within acceptable voltage ranges, and support the Company's CVR subprogram. Company witness Kelly introduces and further discusses this program. This testimony will focus on the LVD subprograms:

(i) LVD Lines Capacity;

(ii) LVD Transformers Capacity;

(iii) LVD New Business Capacity; and

(iv) CVR.

Projected spending is explained in greater detail in the subprogram sections below. The LVD Transformers Capacity subprogram is part of a single-purchase plan, and is covered in the Meters and Transformers section of this testimony.

Q. Does the Company use AMI data in its planning process?

A. Yes. The Company's AMI system collects the total kWh delivered, total kWh received, the total kilovolt-amperes-reactive-hours ("kvarh") delivered, total kvarh received, and average voltage over the meter reading interval, which can be hourly or every 15 minutes, depending on the meter. The Company uses AMI data to identify the frequency and length of customer outages, and that information is used to inform and focus distribution planning Additionally, kVA values in the Customer Loads database are derived from monthly AMI billing consumption data, and used by the Company's distribution power flow model, CYME, for purposes of modeling load at the customer level. The Company uses CYME[8] power engineering software to analyze loading on the distribution system. Company witness Scott A. McPhail's testimony discusses a Load Flow Tool Upgrade that is needed to enable the full time-series benefits of AMI datasets in CYME.

Q. Does the Company consider Non-Wires Solutions ("NWS") in its planning processes?

A. Company witness Kelly discusses the Company's current position on NWS in his direct testimony. The Company is developing a new NWS pilot in 2025 that it plans to submit outside of the regular rate case process in the Commission's expedited pilot process.

LVD Lines Capacity

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Lines Capacity subprogram.

A. Capital investments in the LVD Lines Capacity subprogram address and reduce overload risk on components of the LVD lines system. All components on the system have a rating for their maximum designed load, and while any individual component can withstand

[8] CYME is the trade name of the software, which was previously named Chinh Yvan Micro Engineering.

loading to greater than 100% of this level for a short time, overloads that are too long or too frequent lead to deterioration and increased risk of failure. Investment in this subprogram responds to risks that already exist due to load growth or load shifting from one area of the system to another. These investments fund critical projects to address capacity loading issues in accordance with planning criteria and to address new distributed load additions to ensure that the LVD system can accommodate projected distribution loads. Investments in this subprogram are divided into two categories: equipment upgrades and lines capacity projects associated with substation projects.

Q. Why does the Company invest in LVD Lines Capacity projects to upgrade or replace overloaded lines and equipment?

A. The Company upgrades or replaces overloaded lines and equipment to reduce reliability and safety risks, including equipment failure; nuisance disruptions of sectionalizing devices (e.g., fuse links melting); potential oil spills; equipment heating with a potential risk of fire; inadequate voltage to downstream customers; and conductor melting or sagging creating a public safety hazard of potential contact. Additionally, fixing overload risks on the LVD system better positions the system to accommodate future growth of EV charging, heating electrification, and other customer adoptions of new technologies.

Q. Why does the Company invest in LVD Lines Capacity projects associated with substation capacity projects?

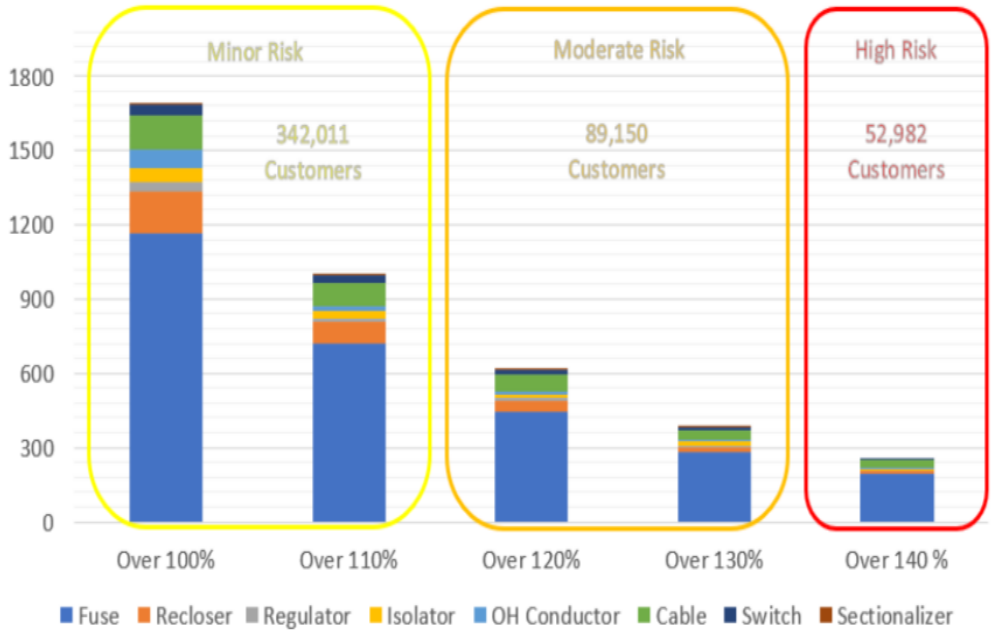
A. Substations are part of the backbone infrastructure of the electric distribution network; therefore, LVD Lines Capacity projects must be completed to reduce the risk of failure due to substation equipment reaching capacity limits. When an increase in the transformer equipment size is not a reasonable alternative, other solutions implemented may include a

new substation with LVD line upgrades or line extensions that transfer customers to other nearby circuits to reduce the load on the existing substation equipment.

Q. How are projected LVD Lines Capacity subprogram expenditures aligned with the Reliability Roadmap?

A. The projected expenditures are directly tied to the LVD Overload Risk Reduction plan outlined in the Reliability Roadmap. As the LVD Overload Risk Reduction plan describes, the Company has a significant population of assets that are loaded to greater than 100% of their rating. In the highest-risk situations, assets are loaded to much greater levels than their respective ratings. In the Reliability Roadmap, the Company outlined a plan to address these overload issues; while the bridge period investments in this case are aligned with levels approved by the Commission in Case No. U-21585, the test year investments represent the Company's continuation of its efforts to execute this plan at levels defined in the Reliability Roadmap. The plan defined in the Reliability Roadmap is intended to address all components overloaded beyond 100% of their rating in order to eliminate overload-caused outages on the LVD system.

FIGURE 52
QUANTITY OF COMPONENTS LOADED TO SPECIFIC PERCENTAGES, 2024



Q. Did the Company consider any alternatives to this approach?

A. Yes. The Company could continue to allow assets on its system to be regularly overloaded, but this simply magnifies risk to the system, especially in a situation in which summer temperatures and, therefore, summer cooling load continue to increase. It is more prudent to address overload risks proactively. With that in mind, the Company does work to develop projects that will best address overload risk from among available alternatives. Projects in this subprogram are developed by the LVD circuit planners to address the identified capacity issues. They identify the best method of improving the issue using the various approaches described above. The Company prioritizes capacity projects based primarily on overload level, addressing the highest overloads prior to lower overloads, with adjustments made for other factors such as historical reliability, customer mix, and safety impact.

Q. How does the Company identify capacity issues that would require an LVD Lines Capacity project?

A. The Company's project selection follows three steps:

(i) considering peak loads;

(ii) comparing peak loads to failure criteria; and

(iii) ranking components by their percentage of overload.

Q. What is the significance of considering peak load in this subprogram?

A. All planning activities in this subprogram are based on projected peak load conditions, which is when capacity is most challenged. The Company uses normal or continuous ratings for peak load conditions, due to the heightened risk of equipment failure or degradation when operating above the capability rating. The loadings on equipment are established by the manufacturer or by a recognized industry source such as the Institute of Electrical and Electronics Engineers, and specify the optimal operation of the equipment based on the capability characteristics of the components. The specific evaluation of each piece of equipment depends on its use. For example, equipment using oil is rated based on a temperature limit not to be exceeded. If that operating temperature is exceeded, then the equipment can start to break down and possibly lead to a shorter lifespan. Other equipment has a defined set of characteristics that, when taken beyond the manufacturer specifications, can lead to a change in characteristics of the material, altering its strength and durability.

Q. Please describe the Company's power flow study process to evaluate the LVD system's ability to handle peak loads.

A. The Company evaluates the LVD system using CYME, an industry-standard power flow software, to perform a power flow analysis. CYME uses load information from two databases to perform power flow studies: the Feeder Demand database and the Customer Loads database. The Feeder Demand database provides the maximum amperage experienced on the circuit with data from substation metering equipment. The Customer Loads database uses customer meter data. The CYME power analysis compares the Feeder Demand load at the substation to the Customer Load distributed across the circuit to determine power flow, voltages, and system protection needs. This analysis is performed on present and future states of the system. This process identifies overloaded distribution equipment and instances of unacceptably low or high voltage during system peak load conditions.

Q. How often does the Company conduct these power flow studies?

A. The Company annually evaluates loading on its LVD distribution equipment, using CYME, for capacity planning purposes. Additionally, studies are completed throughout the year to address emergent issues such as load transfers, generator interconnections, new customer load additions, and reliability failures.

Q. After the power flow study is performed, how does the Company determine if an LVD Lines Capacity project is required?

A. Capacity planning criteria requires that a component of the distribution system have a projected load higher than its capacity, based on Company standards for capacity, before developing a potential capacity project. At present, this requires that a component of the

distribution system experience a load more than its capacity a minimum of one year prior to a capacity project being initiated.

Q. What other factors does the Company consider when determining if an LVD Lines Capacity project is required?

A. Previous year loadings and future customer growth are considered when projecting future loadings. While most equipment has emergency ratings that enable higher capacity for short durations, these are not considered during capacity planning, since loading at these higher levels results in degradation and eventual failure.

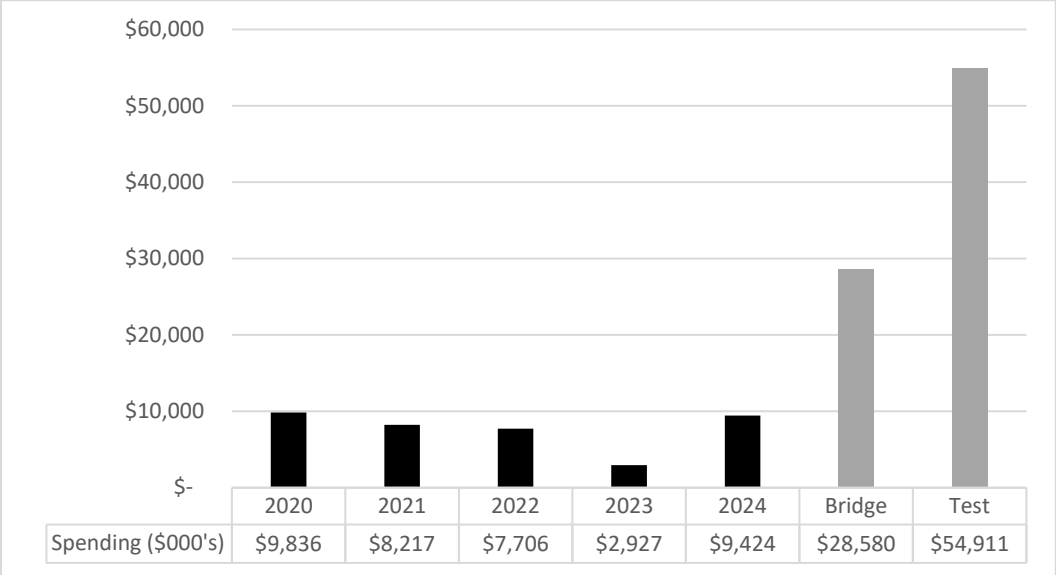
Q. Has the Company considered the impact the adoption of EVs may have on its LVD system?

A. Yes. As the Company continues to support EV growth as described by Company witness Jeffrey A. Myrom, the first step to understanding LVD system impact is to predict when and where EVs will charge. To that end, the Company has conducted an EV propensity study in the past to consider potential concentration of at-home residential charging on certain circuits, which was discussed in detail by Company witness Donald A. Lynd in Case No. U-21585. To date, this is still the most recent propensity study conducted by the Company. Note that larger scale charging is expected to be a spot load and be addressed through the Company's LVD Lines New Business and LVD New Business Capacity subprograms. Company witness McPhail discusses the need for a Load Flow Tool Upgrade to enhance the Company's ability to forecast and simulate the impacts of EVs and other customer technology adoption on the distribution system. This initiative is necessary to integrate EV propensity studies, such as the one mentioned above, with the CYME software as a regular and repeatable step in the capacity planning process.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines Capacity subprogram?

A. The Company is projecting LVD Lines Capacity capital expenditures of $28,580,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 22, column (k), and $54,911,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 22, column (l). The Company's historical actual spending in the LVD Lines Capacity subprogram, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 22, and below in Figure 53. As discussed above, the increase in spending in the bridge period is aligned with what the Commission approved in Case No. U-21585, and the further increase in the test year is aligned with the Company's Reliability Roadmap goal of addressing all assets loaded beyond 100% of their ratings.

FIGURE 53
LVD LINES CAPACITY SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$9,836	$8,217	$7,706	$2,927	$9,424	$28,580	$54,911

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this subprogram will be allocated across the two investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 54.

FIGURE 54
LVD LINES CAPACITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Overloaded equipment upgrades	$21,365,000	125	$53,103,000	278
Lines capacity projects assoc. w/ substation work	$7,215,000	12	$1,808,000	3
Total	**$28,580,000**		**$54,911,000**	

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Lines Capacity subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-166 (JMP-1), pages 29 through 31, and for the test year, listed in Exhibit A-167 (JMP-2), pages 23 through 27. The Company developed the projected costs of the projects in these exhibits considering estimated costs for materials and labor, and the Company's previous experience performing similar projects. These exhibits also identify the location and benefits of the projects.

Q. Please explain the year-over-year historical variation in spending in this subprogram.

A. In 2019, significant increases in LVD New Business, Asset Relocations, and Demand Failures work, as discussed elsewhere in my direct testimony, required the Company to shift resources away from LVD Lines Capacity to focus on work within those subprograms. A similar shift of resources was required in 2023.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Lines Capacity subprogram?

A. This subprogram prevents future failures that would increase SAIDI if they occurred. The investments made to upgrade overloaded assets and alleviate voltage issues increase the longevity of the equipment and prevent service issues and interruptions to customers while improving employee and public safety. The benefits of each project in this subprogram are identified in the Benefit Type and Benefit columns of Exhibit A-166 (JMP-1), pages 29 through 31, and for the test year, listed in Exhibit A-167 (JMP-2), pages 23 through 27.

Q. Does an average unit cost accurately reflect the expected spend per project for this subprogram?

A. No. Average unit cost is not a good measure of spend to predict the cost of an individual project in this subprogram. There is a wide variance among work required, ranging from $2,000 for a protective device upgrade to $2,000,000 for a multi-mile voltage conversion project.

LVD New Business Capacity

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD New Business Capacity subprogram.

A. Equipment and lines need to be added or upgraded for new customers or to maintain adequate service to existing customers when they increase their load beyond existing capacity. Projects in the LVD New Business Capacity subprogram are generally similar in scope to projects in the LVD Lines Capacity subprogram. Because work in this subprogram is driven by customer requests, the Company does not plan or prioritize projects far in advance in this subprogram.

Q. Is there a specific timeframe that the Company needs to complete a New Business Capacity project?

A. Yes. Each new business capacity project needs to be constructed on the same timeframe as the customer load addition that is driving the project to avoid overload of the LVD system. Accordingly, the Company has little latitude on whether to delay or defer these new business capacity projects.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD New Business Capacity subprogram?

A. As with other Capacity subprograms, work in the LVD New Business Capacity subprogram ensures the reliable distribution of electricity to customers by preventing overloads on the system that can cause outages and poor voltage service. The LVD New Business Capacity subprogram provides the added benefit of allowing customers, particularly in the commercial and industrial ("C&I") sectors, to expand their activities and drive economic growth in Michigan. Although spending in the LVD New Business Capacity subprogram is not explicitly tied to the LVD Overload Risk Reduction plan in the Reliability Roadmap, work in this subprogram does increase the capacity of the system, which thereby reduces the risk of future overloads while accommodating new customer loads.

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD New Business Capacity subprogram.

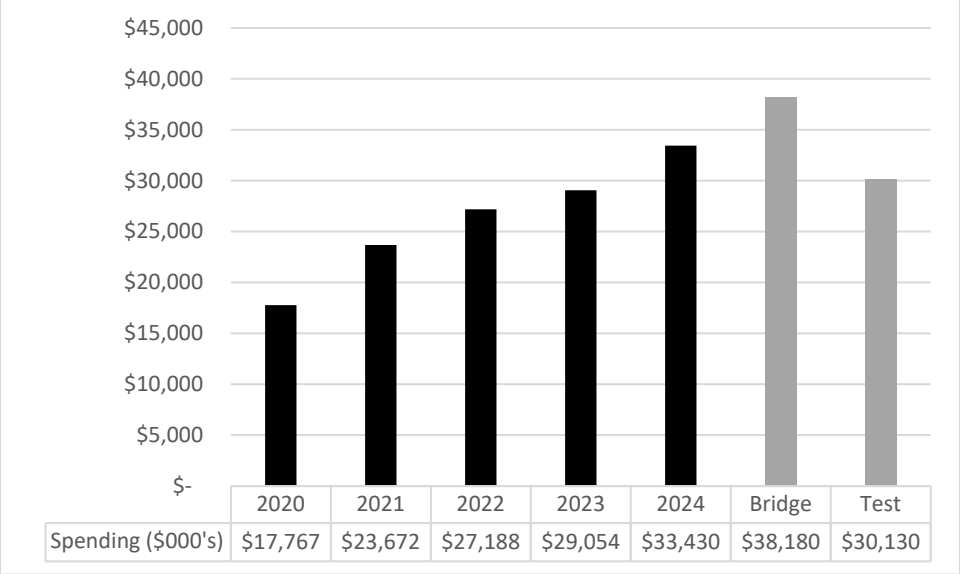
A. The Company has identified projects for the bridge period, which are listed in Exhibit A-166 (JMP-1), pages 32 through 36. Due to the nature of the New Business Capacity subprogram, only projects known in advance are listed. Accordingly, the bridge period list

is not a complete list of all work that will be performed, and the Company is not yet aware of specific projects for the test year. The Company developed the projected costs of the projects in this exhibit considering estimated costs for materials and labor, and the Company's previous experience performing similar projects.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD New Business Capacity subprogram?

A. The Company is projecting LVD New Business Capacity capital expenditures of $38,180,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 25, column (k), and $30,130,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 25, column (l). The Company's historical actual spending in the LVD New Business Capacity subprogram, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 25, and below in Figure 55.

FIGURE 55
LVD NEW BUSINESS CAPACITY SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$17,767	$23,672	$27,188	$29,054	$33,430	$38,180	$30,130

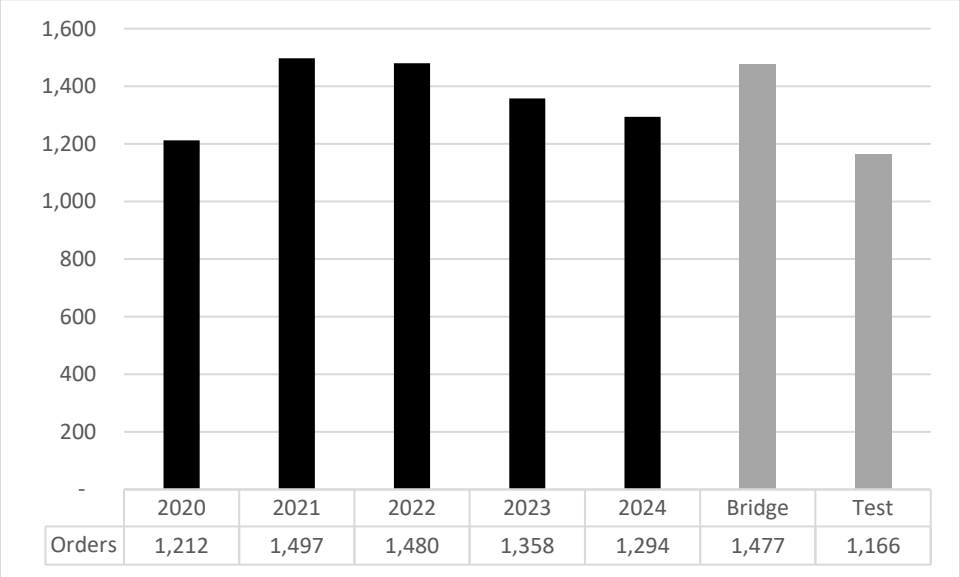
Q. How did the Company develop its projected expenditures in this subprogram?

A. LVD New Business Capacity work is based on customer-driven needs, therefore the Company bases its spending projections on historical actual spending with adjustments for observed trends. The Company has been experiencing an increase in spending on LVD New Business Capacity in recent years. Note that the projected bridge period and test year investment levels represent a modest increase from the five-year average, but they are on par with the Company's 2023 actual investment level and lower than the 2024 actual level (on an annual basis). The number of new business capacity orders per year increased from 1,170 in 2019 to an average of 1,377 over the last three years. Considering that fewer new business connections are expected, as described in the LVD Lines New Business section of testimony, and overloads will be reduced through the increased investment in the LVD Lines Capacity subprogram, the number of orders in this subprogram is expected to decline. However, there is not a one-to-one relationship to the LVD Lines New Business subprogram because need in the LVD New Business Capacity subprogram is driven

primarily by larger loads, such as C&I customers. The Company anticipates future per order costs for the bridge period and test year to be similar to costs experienced in 2023 and 2024. The Company projects it will complete 1,477 orders in this subprogram in the bridge period.

The spending amount for the test year was determined based on the anticipated number of orders in the test year. The Company projects it will complete 1,166 orders in this subprogram in the test year. The historical and projected number of orders is shown in Figure 56 below.

FIGURE 56
LVD NEW BUSINESS CAPACITY UNITS

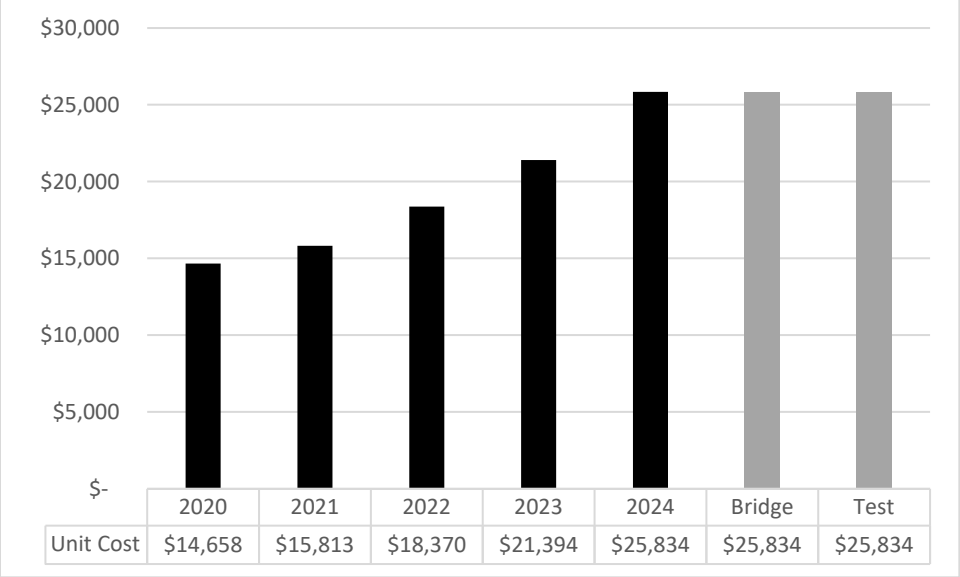


	2020	2021	2022	2023	2024	Bridge	Test
Orders	1,212	1,497	1,480	1,358	1,294	1,477	1,166

Q. What are the historical unit costs for the LVD New Business Capacity subprogram?

A. The historical and projected unit costs of LVD New Business Capacity orders are provided in Figure 57 below. Unit costs in this subprogram have increased due to rising material costs such as cable and poles as discussed in the LVD Lines New Business section of my testimony.

FIGURE 57
LVD NEW BUSINESS CAPACITY HISTORICAL UNIT COSTS



	2020	2021	2022	2023	2024	Bridge	Test
Unit Cost	$14,658	$15,813	$18,370	$21,394	$25,834	$25,834	$25,834

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. Yes, for the overall subprogram. There is a variance of costs among the different projects required ranging from $1,000 for a protective device upgrade to as high as $1,100,000 for the LVD work associated with the construction of a new substation. However, because of the volume of units an average unit cost can be used to develop the spend projections for the overall subprogram.

Conservation Voltage Reduction

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the CVR subprogram.

A. CVR is the capability to optimize service-point—or customer meter voltages—to reduce energy demand without requiring active participation or specific investment by customers. CVR uses a set of technologies, including Volt-VAR Optimization, that reduces the delivery voltage along LVD circuits, thereby reducing the amount of electric load that must

be served on the LVD circuit, and thus, on the electric system. The technology works together and optimizes control settings on both substation and downstream voltage regulating equipment. The technology allows for continuous monitoring and automatic adjustment of these settings to achieve optimal voltage and load reduction while staying within the regulatory requirements. CVR was part of the Company's 2018 Integrated Resource Plan ("IRP") in Case No. U-20165, which was approved by the Commission in 2019, and the 2021 IRP in Case No. U-21090, which was approved by the Commission in 2022. This subprogram of the Capacity Program funds capital projects necessary for implementing the Company's overall CVR plan that is included in the IRP.

Q. What is included in these capital projects?

A. The purpose of these projects is to install and upgrade equipment to ensure that the targeted LVD circuits can enable CVR without providing voltage to customers outside the allowable range. These projects include installing Distribution Supervisory Control and Data Acquisition ("DSCADA"), regulator controllers, and capacitor controllers on targeted circuits, as well as work to address potential voltage issues. The Company uses AMI data to determine voltage levels being provided to customers; if a customer's existing voltage is outside the range that would allow CVR optimization, the Company will complete circuit conditioning work, including but not limited to transformer upgrades, line reconductoring, as well as other solutions to improve the voltage.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the CVR subprogram?

A. The benefits of CVR were discussed in the Company's IRP filings in Case Nos. U-20165 and U-21090. In those filings, the Company forecasted that CVR would provide energy

and demand savings, as well as loss reduction, as shown in Figure 58. The amount of energy savings for each project in this subprogram are identified in the Benefit Type and Benefit columns of Exhibits A-166 (JMP-1), page 37, and A-167 (JMP-2), page 28.

FIGURE 58
CVR CUMULATIVE ENERGY AND DEMAND SAVINGS

	Actual[9]					Projected[10]						
Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cumulative Peak MW Reduction	0.4	5.6	14.7	21.2	~~39.1~~ 18.7	51	62	73	84	95	105	113
Cumulative MWh Reduction	82	5,643	23,882	69,045	125,746	119,379	144,102	168,971	193,976	219,160	244,450	262,399

Q. How does the Company ensure proper measurement and verification of CVR performance?

A. When the Company initially began enabling CVR on LVD circuits in 2019, the Company tested CVR performance by cycling CVR on and off on successive days and using substation DSCADA data and customer smart meter data to measure actual CVR savings by comparing data when CVR was on versus when it was off. This initial testing creates a baseline for CVR performance. Once CVR is fully enabled and operational on a circuit, the Company's DSCADA and meter data provides sufficient telemetry to ensure continuous measurement and verification of CVR performance. A third-party evaluator has also verified that the methodology and the results obtained from the Company's analysis are valid and that it is reasonable to assume similar results will be obtained from additional circuits as CVR is enabled. The full report of the third-party evaluator is provided in Exhibit A-168 (JMP-3).

[9] Actual data from Case No. U-20165, Annual Cost Reports, Exhibit 2, columns (o) and (q), Total row.
[10] Projected data from Case No. U-21090, Exhibit A-86 (MSH-1).

Q. How does the Company identify CVR projects?

A. CVR circuits are selected primarily based on customer types and circuits with smart grid capabilities. Smart grid equipment will eventually be available on approximately 85% of the LVD circuits; therefore, circuits that are not cost-effective for DSCADA deployment are ruled out from CVR consideration. Additionally, circuits that contain primarily C&I customers were removed. The principal reason for this is that industry analysis has shown that CVR is more effective on residential load types. From within this circuit candidate pool, circuits are selected based on those that had lower anticipated costs. For example, circuits that have already deployed the necessary upgrades to substation and line equipment were prioritized. Additionally, circuits where less capital investment would be required, as determined by a power flow study, were prioritized. The power flow study process also identifies the various projects needed to enable CVR for each circuit.

Q. Please identify the projects that will be accomplished with the requested spending level in the CVR subprogram.

A. The Company has identified upgrades to 75 circuits for the bridge period, listed in Exhibit A-166 (JMP-1), page 37, and 85 circuits for the test year, listed in Exhibit A-167 (JMP-2), page 28. The Company developed the projected costs of the projects in these exhibits considering estimated costs for materials and labor, and the Company's previous experience performing similar projects. These exhibits also identify the location and benefits of the projects.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the CVR subprogram?

A. The Company is projecting CVR capital expenditures of $5,586,000 for the bridge period, as shown in Exhibit A-113 (MPK-3), line 26, column (k), and $4,070,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 26, column (l). This level of spending will enable the Company to add CVR to 85 circuits in 2025 and 85 circuits in 2026.

Q. How did the Company develop its projected expenditures in this subprogram?

A. Spending in this subprogram is designed to implement the Company's CVR plan, as originally proposed and approved in Case No. U-20165, subsequently updated, and approved in Case No. U-21090. Further, the implementation plan remains consistent with the plan presented in Case No. U-21389, with approximately 85 circuits planned per year until the final year of deployment in 2030.

Q. What has been the historical actual spending in the CVR subprogram and how does that compare to prior cases?

A. Comparisons of historical spending, projected expenditures in the case, and past approved IRP projections are shown in Figure 59. The cumulative historical expenditures plus projected expenditures in this case are compared to the cumulative approved IRP projections in Figure 59. The Company has maintained its cumulative CVR historical expenditures and rate case projected expenditures at or below the cumulative projections provided in the IRP cases.

FIGURE 59
CONSERVATION VOLTAGE REDUCTION EXPENDITURES

	Projected			Historical
	U-20165[11]	**U-21090[12]**	**This Case**	**Expenditures**
2018	$970,000			-
2019	$1,700,000			$81,743
2020	$2,500,000			$1,936,593
2021		$4,070,930		$7,191,370
2022		$4,151,389		$3,145,109
2023		$3,964,031		$1,311,828
2024		$3,877,052		$2,246,000
2025 Bridge Period		$4,391,000 --	$4,391,000 $5,586,000	
2026 Test Year			-- $4,070,000	
2020-2024 Five-Year Average	$3,712,600			$3,166,000
2018-2024 Total	$21,233,000			$15,939,643
2018-2026 Total	**$25,624,000**		**$25,595,643**	

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. No. Average unit cost is not a good measure of spend to predict the cost of an individual project in this subprogram. There is a wide variance among work required ranging from $5,000 to as high as $400,000 per project.

Metering and Transformers

Q. What will the Meters and Transformers portion of your testimony discuss?

A. This section will address the Company's single purchase plans for LVD Metering and LVD Transformers. Projected spending and benefits are explained in detail in the sections below.

[11] Case No. U-20165, Exhibit A-67 (MAO-1), column (e).
[12] Case No. U-21090, Exhibit A-87 (MSH-2), column (f).

LVD Metering

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Metering subprogram.

A. The LVD Metering subprogram supplies meters and associated equipment including meter sockets, metering transformers, and meter testing equipment. Historically, LVD Metering expenditures were allocated between the New Business and Demand Failures programs, but LVD Metering has always operated through a single purchase plan, and in this filing the Company has combined them into a single subprogram under Demand Failures. Meter Sockets and Electric Capital Meter Test Equipment costs are allocated across the total meter and metering transformer units to determine the overall cost per unit for this subprogram.

Q. How are the projected LVD Metering expenditures aligned with the Reliability Roadmap?

A. Following the Commission's March 1, 2024 Order in Case No. U-21389, the Company decided to defer replacement of 4G LTE meters to a later date. The Company's 4G LTE communications network provider has not provided a definitive date for the retirement of the 4G LTE network, but expect to maintain the network into the mid- to late- 2030s. With that in mind, the Company is evaluating its existing metering technology, vendors, and software, including technology to support future electric and gas system integrations. By year-end 2025, the Company expects to have defined an approach for eventually replacing 4G meters.

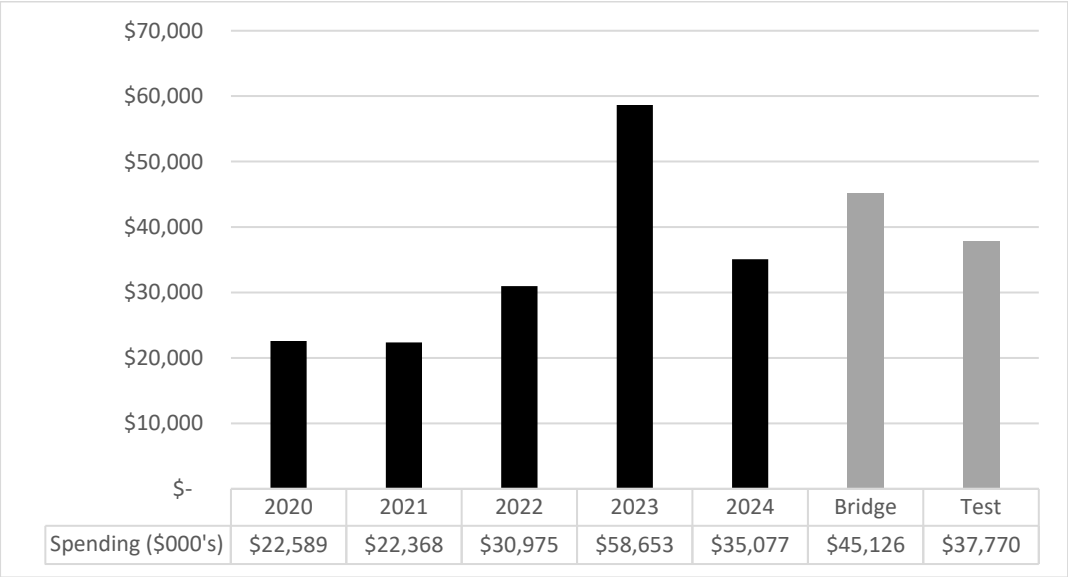
Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Metering subprograms?

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each of the metering subprograms as identified in Figure 60 below. The projections for LVD Metering capital expenditures are shown in Exhibit A-113 (MPK-3), line 35, columns (k) and (l). The Company's historical actual spending in the LVD Metering subprograms, along with the bridge period and test year forecasts, are shown below in Figure 61.

FIGURE 60
METERING SUBPROGRAMS EXPENDITURES AND UNITS

Subprograms	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
LVD Metering New Business	$18,050,400	27,634	$15,108,000	20,726
LVD Metering Demand Failures	$27,075,600	41,451	$22,662,000	31,088
Total	**$45,126,000**	**69,085**	**$37,770,000**	**51,814**

FIGURE 61
LVD METERING SUBPROGRAMS TOTAL EXPENDITURES



Q. How did the Company develop its projected expenditures in the LVD Metering subprograms?

A. The expenditures in the metering subprograms are based on projected activity in the New Business and Demand Failures subprograms, which is in turn based largely on historical data. The Company also considers estimates of new business connections in future years and forecasted large project work.

Q. What benefits will customers realize through the Company completing work in the LVD Metering subprograms?

A. Metering is an essential part of the Company's broader requirement to connect new customers through its overall New Business Program, as well as to replace failed equipment through the overall Demand Failures Program. Additionally, advanced metering is an essential component in many of the Company's present and future demand response and renewable programs.

The New Business subprogram, in combination with the Demand Failures subprogram, maintains metering accuracy by replacing meters in-service that are nonfunctional, damaged, or whose accuracy has been questioned by the customer. New meters are tested upon purchase to ensure meters being deployed to new business and demand failure locations are compliant with accuracy requirements.

Q. What are the historical unit costs for the LVD Metering subprograms?

A. Historical unit costs for the LVD Metering subprograms are provided in Figure 62 below. Note for 2021, 156,960 smart meters were replaced as part of the 3G to 4G-CatM1 changeout project; the replacement meter came with new functionality, the ability to communicate with gas meters, at a cost of $7 per meter. This increased functionality allows

all the Company's smart meters to communicate with gas meters, allowing the meters to be used throughout the service territory. Including these meters in the subprogram unit cost calculation skewed the unit cost for 2021 to $109. If these units are not included in the unit cost calculation, the unit cost for 2021 is $432. This skewing also occurred in 2022, though to a smaller extent, from $541 to $253 per unit.

The table in Figure 62 breaks out the categories of purchases included and the associated unit costs for each category. There are no units for meter sockets and meter test equipment as many of the costs in those categories are minor materials; the total cost of meter sockets and test equipment are allocated across the total units of the other categories. During the bridge period and test year, the overall unit cost is being impacted by several factors. For legacy meters, the Company is purchasing higher cost units for C&I applications, to accommodate those customers' complex billing and data requirements. The Company had been using and recycling inventory of these units, but the vendor discontinued the models that were being used. The new units are more expensive, and the Company is acquiring a working inventory over the bridge period and test year. The increase in metering transformer units, meter socket spending, and polyphase smart meter purchases are related to conversions of 400-amp services from present configurations to instrument transformer rated installations. Presently, any meter work at these locations requires de-energization to do the work safely. Transitioning these to transformer rated installations will increase safety for Company employees and customers.

FIGURE 62
LVD METERING UNITS AND UNIT COSTS

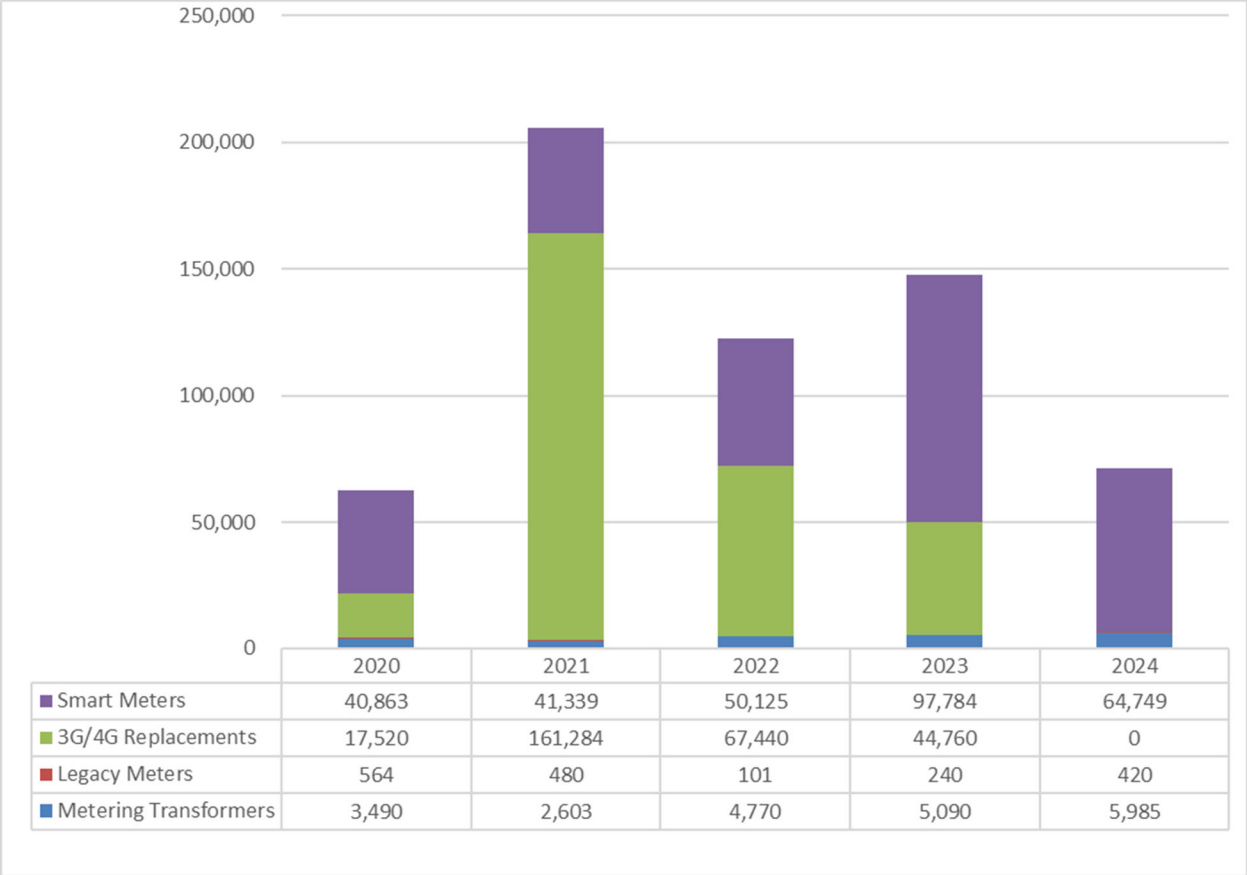
	2020	2021	2022	2023	2024	Bridge	Test
Legacy Meters							
Legacy Units	564	480	101	240	420	1,387	1,040
Unit Cost	$ 1,485	$ 105	$ 1,359	$ 149	$ 1,033	927	$ 927
Smart Meters							
Smart Meter Units	40,863	41,339	50,125	97,784	64,749	56,864	42,648
Unit Cost	$ 311	$ 293	$ 371	$ 366	$ 223	229	$ 306
3G/4G Replacements							
3G/4G Units	17,520	161,284	67,440	44,760			
Unit Cost	$ 9	$ 20	$ 18	$ 208			
Metering Transformers							
Transformer Units	3,490	2,603	4,770	5,090	5,985	10,835	8,126
Unit Cost	$ 2,026	$ 1,842	$ 1,759	$ 1,743	$ 988	$ 748	$ 761
Meter Sockets & Test Equipment							
Spending (000's)	1,821	2,244	2,642	3,763	2,974	5,213	3,910
Allocated Unit Cost Impact	$ 29	$ 11	$ 22	$ 25	$ 42	$ 75	$ 75
Total Subprogram							
Total Units	62,437	205,706	122,436	148,874	71,154	69,085	51,814
Total Unit Cost	$ 362	$ 109	$ 253	$ 390	$ 493	$ 653	$ 729

Q. Please explain the variation in total costs and in unit costs over time.

A. Total expenditures for LVD Metering have varied from year to year based on the mix in quantity and type of meters, metering transformers, and meter sockets the Company has had to purchase. During 2021, 2022, and 2023, the Company experienced increased meter failures due to contaminated meter batteries. This failure primarily occurred in meters that were outside of the manufacturer warranty period of three years. To replace the failed meters, the Company purchased additional meter quantities in 2022 and 2023 to meet the demand for failure replacements, and to complete 3G meter conversions. The unit cost for meters includes dollars allocated for meters, metering transformers, and meter sockets. The

overall variation in the unit cost of meters is also related to variation in the mix both in quantity and type of devices, as shown in Figure 63.

FIGURE 63
LVD METERING UNITS



	2020	2021	2022	2023	2024
Smart Meters	40,863	41,339	50,125	97,784	64,749
3G/4G Replacements	17,520	161,284	67,440	44,760	0
Legacy Meters	564	480	101	240	420
Metering Transformers	3,490	2,603	4,770	5,090	5,985

The average unit costs in the metering transformer category were consistent from 2019 through 2023. For 2024, the unit costs were lower due to the mix of transformers purchased, with an increase in the number of smaller, less expensive current transformers. In 2021 and 2023, legacy meter unit costs were lower due to the quantity and mix of meters purchased. In 2021 and 2023 the only legacy meters purchased were 2S 200 Amp residential meters. For the other years, including the forecast for the bridge period and test year, there are higher quantities of polyphase meters included that are read via the

Company's MV90 system. They are categorized as Legacy meters as they were not part of the Smart Energy Deployment project. These meters are installed on large C&I electric customer locations. Smart meter unit costs were lower in 2021 due to lower numbers of polyphase meters purchased, then increased in 2022 and 2023 due to the purchase of more polyphase meters. Smart meter pricing is contractually fixed until 2032.

Q. Why is the Company continuing to purchase any legacy meters after the end of the implementation of smart meters?

A. The legacy meters in the Company's purchase plan primarily support operation of MV90 meters. MV90 meters essentially provide a type of automated meter reading for approximately 5,000 large C&I customers, by which meter interval data is collected either by an internet-over-IP or telephone communication with the meter. MV90 meters were determined to be out of scope for initial smart meter deployment for two main reasons. First, the billing tariffs for these customers are complex and would have required extensive hours of programming; since MV90 was already functional, the Company kept these meters out of scope for initial smart meter deployment. Second, some of these MV90 meters have a pulse output to provide real time data to customers and at the time of smart meter implementation through the present time, the meter vendor did not offer a smart meter option with pulse output, so the use of MV90 legacy meters was still required. Legacy meters, in very small numbers, are also purchased to support metering installations for customers who opt-out of the smart meter program.

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. No. Average unit cost is not a good measure of spending per project for this subprogram. There is a wide variance among different meter types ranging from $125 per meter to as high as $6,000 per meter. There is also a wide variance among metering transformers and meter sockets. Metering transformers range from $60 per unit to $2,500 per unit and meter sockets range from $26 per unit to $911 per unit. When projecting annual spend in this subprogram, the Company does use historical usage across meter types over the last three years, as shown in Figure 64, as the basis for future purchase plan quantities. In addition, the plan considers major known projects that will require metering and associated devices in establishing the purchasing plan by device type. This establishes the meter mix and subsequent unit price submitted in the rate case. As the actual year progresses, the mix of meters will change based on the actual work mix requiring meters and associated devices that will impact the unit prices from year to year.

LVD Transformers

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Transformers subprogram.

A. The LVD Transformers subprogram supplies the distribution transformers that provide the means to supply electricity to customers at an acceptable voltage, with the number of transformers needed driven primarily by activity in the LVD Lines New Business subprogram. Historically, LVD transformers purchases have been allocated across the New Business, Demand Failures, and Capacity programs for accounting reasons, but because these separate LVD transformers subprograms operated through a single purchase

plan for distribution transformers, the Company is combining all LVD transformer purchases into a single subprogram under New Business for rate case purposes.

Q. How are the projected LVD Transformers expenditures aligned with the Reliability Roadmap?

A. As noted in the Reliability Roadmap, supply chain issues have led to an increase in the unit costs of transformers, and while the Company is working to diversify its supply chain, it must continue to purchase transformers to meet customer demand, and in fact must increase purchase levels to catch up from shortages experienced during the COVID-19 pandemic.

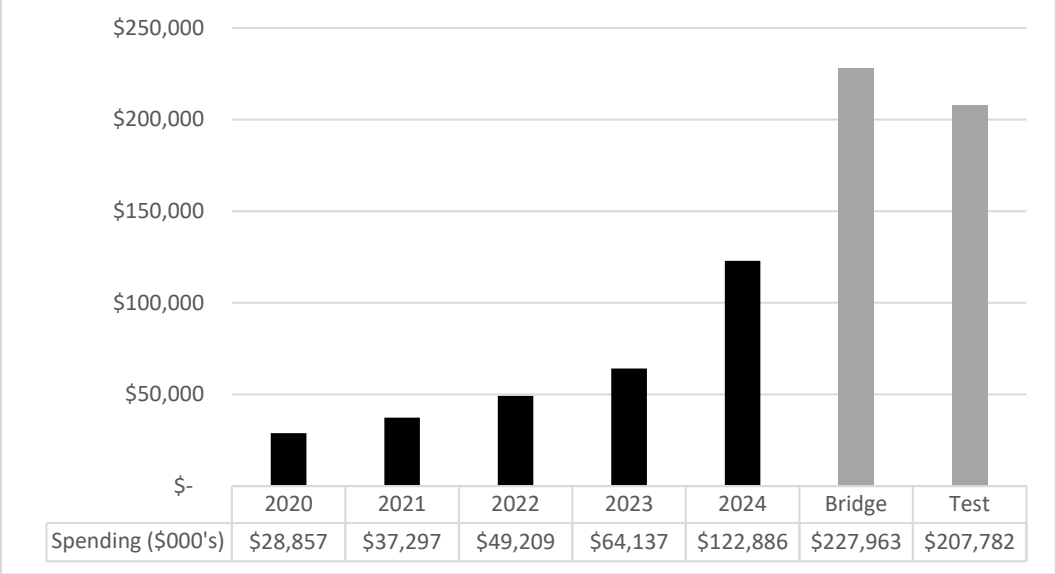
Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Transformers subprograms?

A. The installation of distribution transformers is an essential part of the Company's broader requirement to connect new customers through its overall New Business Program, the benefits of which were described earlier in my direct testimony. The benefits of specialized transformers like voltage regulators allow the Company to condition the voltage on distribution circuits to ensure service to customers is delivered within the voltage range specified in Company tariffs.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD transformers subprograms?

A. The Company is projecting LVD Transformers capital expenditures of $227,963,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 5, column (k), and $207,782,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 5, column (l). The Company's historical actual spending in the LVD Transformers subprograms, along with the bridge period and test year forecasts, are shown below in Figure 64.

FIGURE 64
LVD TRANSFORMERS SUBPROGRAMS TOTAL EXPENDITURES

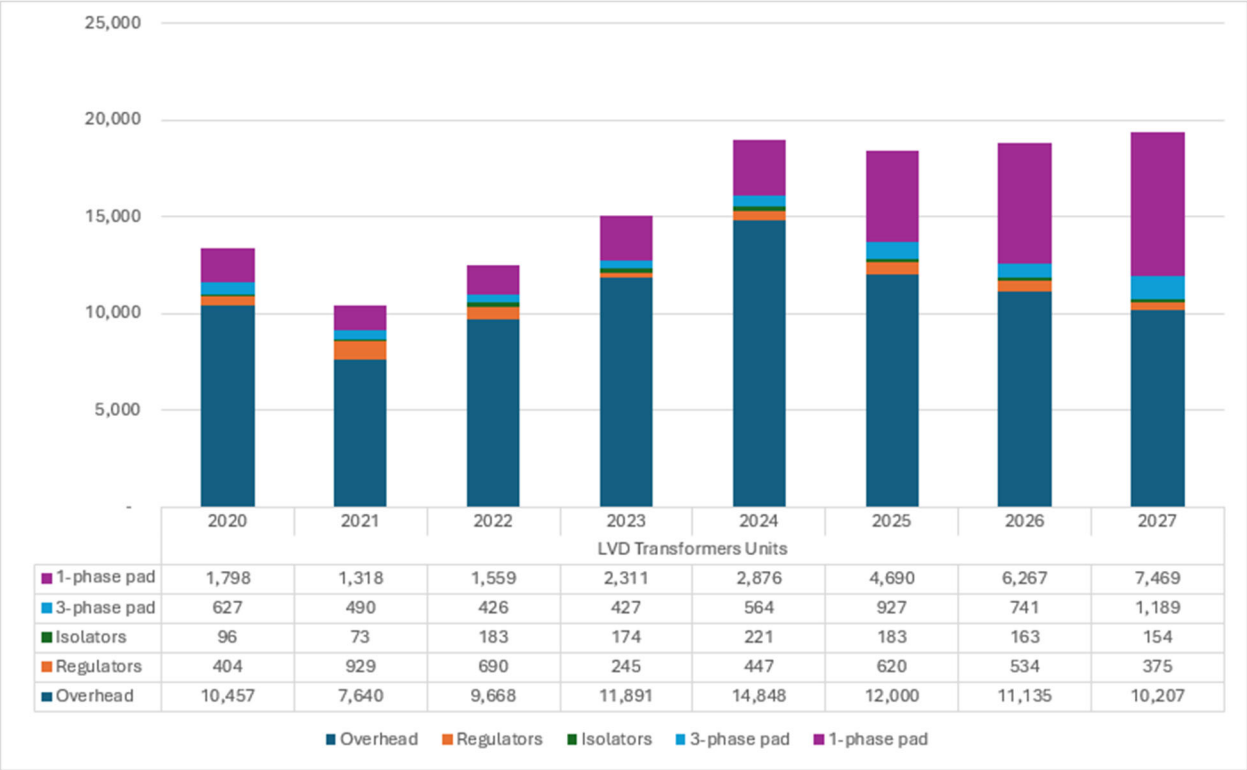


Q. How did the Company develop its projected expenditures in the LVD Transformer subprograms?

A. The Company develops its distribution transformer purchase plan by estimating the total number of transformers needed, based on historical actual data, with potential fluctuation in individual years based on lines projects in the Company's reactive spending programs. The historical number of transformer purchases (for 2020 through 2024) is shown in Figure 65 below, followed by projected purchases in future years (for 2025 through 2027). In 2025 and beyond, the Company expects that purchases of overhead transformers will remain generally level, but the Company is planning for a continued significant increase in purchases of padmount transformers tied to increased undergrounding work for both new service connections and primary and secondary circuits; for general new business work; and for the need to support customers adopting EVs as described in the Reliability Roadmap. Furthermore, in 2022, the supply market for transformers in the United States

dropped significantly due to shortages in labor and raw materials, and the Company continues to invest in higher levels for purposes of ensuring it has restocked its inventory.

CORRECTED FIGURE 65
LVD TRANSFORMERS UNITS

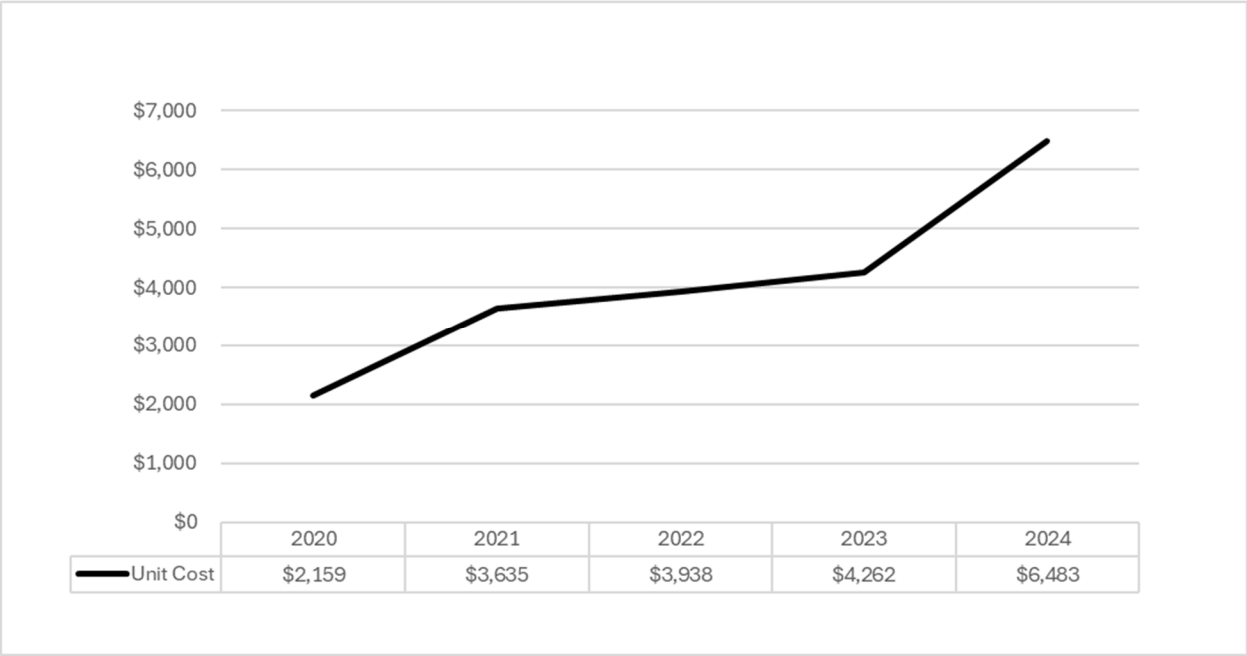


LVD Transformers Units	2020	2021	2022	2023	2024	2025	2026	2027
1-phase pad	1,798	1,318	1,559	2,311	2,876	4,690	6,267	7,469
3-phase pad	627	490	426	427	564	927	741	1,189
Isolators	96	73	183	174	221	183	163	154
Regulators	404	929	690	245	447	620	534	375
Overhead	10,457	7,640	9,668	11,891	14,848	12,000	11,135	10,207

Q. What are the historical unit costs for the LVD transformers subprogram?

A. The historical unit cost of transformers is provided in Figure 66.

FIGURE 66
LVD TRANSFORMERS UNIT COSTS



Q. Please explain any variation in unit costs over time.

A. Unit costs for transformers have increased over the historical period, partially due to inflation. The transformer sector, as an industry, has experienced at least a 6% increase year-over-year in cost, and this increase is projected to continue at 5% in the future. Additionally, the Company maintains an inventory of more than 400 transformer types, and unit costs each year can vary depending on the mix of transformer types the Company purchases each year. For example, in 2020 the Company received less of the more expensive units like regulators. This, coupled with increased volume of units at a lower cost, led to a lower average cost per unit in 2020. For 2021 and 2022, raw material shortages and labor issues caused domestic supply to shrink and the cost of transformers in each year to increase by 30% over the previous five-year historical averages as noted in this testimony. In total, the cost of padmount transformers increased by 50% from 2022 and 2024 due to demand/supply imbalances.

As a result of these supply challenges, the Company initiated a supply base diversification strategy, including new overseas manufacturers. This supply base diversification was necessary to mitigate lead-time increases and capacity risks with domestic manufacturers. Transportation and higher manufacturing costs from these suppliers led to higher unit costs in 2024 (transportation costs are higher for products that must be shipped from other countries). In addition, demand for lower-priced units like overhead transformers has slowed while demand for larger three-phase and single-phase transformers has increased in this same period. In short, the Company's supply diversification strategy for transformers has better ensured that the Company can meet customer demand, but did involve increased costs.

Q. Does an average unit cost accurately reflect the expected spend per transformer for this subprogram?

A. Unit cost is not an ideal measure of spending to predict the cost of a single transformer in this subprogram, as it includes a wide range of transformer types which are not directly comparable. Transformers can cost as little as $500 but also as much as $15,000 or more depending on application. The transformer purchase plan includes traditional transformers that serve the purpose to provide service to customers as well as specialized transformers like voltage regulators that respond to changes in voltage on the primary system and adjust to ensure adequate voltage. As noted above, demand for larger, higher cost single-phase and three-phase transformers has increased while overhead units have leveled off.

Electric Other Program

Q. What is included in the Electric Other Program?

A. Company witness Kelly introduces the Electric Other Program in his direct testimony. This testimony will address the Tools sub-program. The Electric Other Program also includes the Computers and Equipment; System Control Projects; and Grid Technologies sub-program, which are addressed by Company witness Hayward in her direct testimony.

Tools

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the Tools sub-program.

A. This sub-program covers the purchase of new and replacement tools for utility workers that are worn, broken, outdated, and/or unrepairable when the tools are priced over $1,000 per item. Some examples of these tools covered in this sub-program include:

- Cordless cutting, crimping, and hammering/breaking tools
- Concrete cutting/boring tools with silica mitigation systems
- Remote cutting and spiking tools
- Calibrated metering tools
- Customer service integrity meters
- Sub-Station Testing instruments
- System/service diagnostic or locating equipment
- Line segmenting (load drop/load pickup) devices
- System reconductoring accessories
- Specialty rigging, work lighting, pumping or "bridging" and "matting" equipment

Since 2016, this sub-program included outfitting new Company trucks, including service bucket trucks, two-person buckets, and digger derricks with standard packages of essential tools to ensure that crews go into the field with appropriate equipment, referred to as "truck tool kits." The funds for these truck tool kits are transferred from the Tools sub-group to Fleet, allowing for the purchase of the truck tool kits to coordinate with the purchase/delivery of each new truck. The purchase plan for these truck tool kits is based on the Company's fleet acquisition and deployment plan. As the Company is planning to expand its Operations workforce, the Company will need to purchase additional capital tools (besides truck tool kits).

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Tools sub-program?

A. A properly outfitted truck and crew enable a safer, faster response to outages, safe and efficient installation of new services, and more productive completion of projects with less waste and lower unit costs. Company crews require appropriate tools and equipment when in the field, both to ensure their own safety and the safety of the public, and to be able to complete their work in an expeditious manner to complete maintenance and construction work and reduce outage times. Spending in this sub-program ensures that tools are replaced in a timely manner before the expiration of the tool's life, while ensuring that Company trucks are always stocked with appropriate tools for workers to safely complete their work.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Tools sub-program?

A. The Company is projecting capital expenditures of $10,001,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 43, column (k), and $8,248,000 in the projected test year, as shown in Exhibit A-113 (MPK-3), line 43, column (l).

Q. What is the basis for the Company's projected spending level in this sub-program?

A. The projected spending level in this sub-program is based on the needs of the Company for capital tools and truck tool kits. The cost of capital tools is based on prices quoted from vendors for the specific models. Prices for each tool make and model can vary annually due to inflation and other supply chain constraints.

The tool purchases in the bridge period will support all electric operations, including the new Underground Construction group that focuses on installing new customer underground infrastructure, including primary cable and transformers. Figure 67 outlines the Company's bridge period investment categories and units in the Tools sub-program.

FIGURE 67
BRIDGE PERIOD INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital
Truck Tool Kits (93 units)	$3,362,000
Other Capital Tool Purchases	
General Capital Tools	*$3,039,000*
Reconducting Trailer Equipment	*$100,000*
Employee Fall Restraint	*$250,000*
Klein Bin Storage System	*$600,000*
Substation bird mitigation equipment	*$90,000*
UG Primary Wire Stripper	*$700,000*
Digger Truck 3-Phase Holder	*$250,000*
Meter Service CT Lifters (ergonomics)	*$150,000*
Thumpers	*$100,000*
Magnetic Drills for Ductile Iron Poles	*$100,000*
Light Weight Service Savers	*$600,000*
Underground Department tools	*$660,000*
Total	**$10,001,000**

In the test year, the Company will continue with its process of purchasing truck tool kits for new Company trucks, with 62 truck tool kits in the test year, aligned with the Company's fleet acquisition and deployment plan, necessary to support the Company's expanding workforce to complete the increased workload necessary to address new business requests, system capacity, and system reliability work. The increase in the Capital Tool Purchases category reflects the increased need to support additional work and work groups focused on the HVD system reliability. Due to the nature of this work, the tools purchased for any new or additional group have a specific purpose and voltage rating, thus making the investment more focused on the work practices. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 68 below.

FIGURE 68
TEST YEAR TOOLS INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital
Truck Tool Kits (62 units)	$2,015,000
Other Capital Tool Purchases	
General Capital Tools	$3,069,000
Klein Bin Storage System	$600,000
Reconductoring Trailer Equipment	$180,000
Substation bird mitigation equipment	$100,000
Battery Concrete Saw	$300,000
Underground Work Group Tool Support	$457,000
Fall Restraint	$250,000
Hydraulic Tool Replacements	$1,277,000
Total	**$8,248,000**

Q. Please explain the coordination between Fleet and Electric Operations to procure Truck Tool Kits.

A. Starting in 2016, the Electric Operations Tools sub-program has set aside budgeted dollars to purchase truck tool kits for the bucket and digger trucks that Fleet plans to purchase. The Tools sub-program then transfers the allocated dollars to Fleet, creating a packaged purchase with Fleet's selected vendor. This is done because the tools included in these tool packages are considered standard equipment for the vehicles and ensure that crews go into the field with the necessary resources. In 2022, however, no money was transferred for the purpose of new truck tool kits. Due to Fleet-related disallowances in the Commission's Order in Case No. U-20963, the Company wrote off or sold a number of vehicles. Truck tool kits can only be accounted for in Fleet if there are associated vehicles; the result of this was that no transfers were made in 2022.

Historical data in Figure 69 below shows the overall annual truck tool kit dollars that were earmarked by the Electric Operations Tool department, then transferred to Fleet within the truck purchase.

FIGURE 69
TRUCK TOOL PACKAGES BY YEAR

	2020	2021	2022	2023	2024	Bridge Period	Test Year
Number of truck tool packages	47	18	0	16	24	93	62
Truck tool package spending	$2,736,000	$5,885,000	$0	$560,000	$727,000	$3,362,000	$2,015,000

Q. What has been the historical actual spending in the Tools sub-program for the past five calendar years?

A. The historical actual spending in the Tools sub-program for the past five calendar years is shown in Figure 70 below. This level of spending is what the Company requires to replace capital tools in lifecycle, create consistency (for training and in-field use) between Electric Operations work groups, provide Fall Restraint tools for Apprentices and new hire Journey-workers based on the total of individuals hired, and support the purchase of truck tool packages to equip the Company's growing workforce.

FIGURE 70
TOOLS HISTORIC EXPENDITURES

2020	2021	2022	2023	2024	5-Year Average
$3,611,000	$5,214,000	$5,257,000	$4,560,000	$7,773,000	$5,283,000

Q. Please explain year-over-year variation in spending in this sub-program.

A. Spending in this sub-program has been increasing for three reasons. First, the Company has been purchasing truck tool packages for LVD line worker vehicles since 2016, and in 2021 began purchasing them for other groups in the Electric Operations department as well. Second, tool prices have increased, and the Company has invested in newer types of tools to improve safety. As more tools reach the end of their useful life and must be replaced, the Company's spending in this sub-program has increased to replace older tools with safer and more advanced ones. In particular, the Company has invested in more ergonomic tools, such as battery-operated cutters, drills, impact wrenches, and crimpers, to reduce the frequency and severity of injuries and achieve occupational health goals. Third, the Company has created a new workgroup to support Underground construction. This workgroup has driven an increase in truck tool kit purchases and purchases of tools used in underground utility work.

SUMMARY

Q. Please provide a brief summary of your testimony and the intent of investing in LVD capital subprograms to support the Company's electric distribution system.

A. The testimony provided an overview of the LVD system and associated capital investments to improve reliability and resiliency of the system while serving new customers to support economic development in the state of Michigan. The testimony provided detail of each LVD capital investment program and the basis of planned investments and benefits. The LVD capital investments outlined in my testimony are identified and planned to support the overall objectives and strategy outlined in the Company's Reliability Roadmap and those introduced by Company witness Kelly.

Q. Please summarize the LVD capital expenditure plan in this filing.

A. The LVD capital expenditure plan outlined in this testimony is summarized in Figure 71 below. Dollars shown are in thousands.

FIGURE 71
LVD CAPITAL EXPENDITURE SUMMARY ($000)

	2024 Actuals	Bridge Period	Test Year
LVD Capital	$632,197	$1,055,533	$1,086,679

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

JENNIFER M. PARTLAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Jennifer M. Partlan, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same Jennifer M. Partlan who previously submitted direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Ryan Boutet, Nicholas M. Evans, and Anna N.N. Schiller; Attorney General ("AG") witness Sebatian Coppola; and Association of Businesses Advocating Tariff Equity ("ABATE") witnesses Jessica A. York and Colin T. Fitzhenry.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-225 (JMP-5)	Discovery response 21870-ST-CE-0078;
Exhibit A-226 (JMP-6)	Example of LVD Concept Approval; and
Exhibit A-227 (JMP-7)	Discovery response 21870-AB-CE-0712.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

I. <u>REBUTTAL OF STAFF WITNESS BOUTET</u>

Q. Please summarize Mr. Boutet's direct testimony in this case.

A. Mr. Boutet's testimony is focused on the Company's low voltage distribution ("LVD") capital expenditures. He reviews several of the Company's LVD capital investment

sub-programs and recommends disallowances in six investment areas. I will respond to each of Mr. Boutet's recommendations.

Q. What is Mr. Boutet's recommendation regarding the Company's Conservation Voltage Reduction ("CVR") sub-program?

A. Mr. Boutet notes, on pages 10 and 11 of his direct testimony, that the Company appears to have underspent in the CVR sub-program in 2023 and 2024 when compared to the Company's prior rate case projections. Based on this, he recommends that the approved investment amount for CVR be set at the five-year historical average expenditures plus inflation, and recommends bridge period and test year disallowances to reflect that spending level. These proposed disallowances are equal to $1,158,514 for the bridge period ending December 31, 2025; $91,645 for the four-month bridge period ending April 30, 2026; and $733,454 for the test year ending April 30, 2027.

Q. Do you agree with Mr. Boutet's recommendation for CVR?

A. The Company will not oppose Mr. Boutet's recommendation regarding the CVR sub-program projected expenditures in this case.

Q. What is Mr. Boutet's recommendation regarding the LVD Lines Capacity sub-program?

A. On pages 12 and 13 of his direct testimony, Mr. Boutet expresses concern that the Company can effectively scale up LVD Lines Capacity investment as projected, and he contends that year-to-date spending through June 2025 shows that the Company is on track to underspend its 2025 projection. Mr. Boutet recommends that the Commission approve investment levels for the bridge period, as they are in line with what the Commission approved in Case No. U-21585, but recommends that the Commission not approve the full proposed test year

investment level. Instead, he proposes that test year investment be limited to a doubling of the pace of work approved in Case No. U-21585, with a corresponding disallowance of $18,720,000 in the test year.

Q. How do you respond to this recommendation?

A. The Company will not oppose Mr. Boutet's recommendation regarding the LVD Lines Capacity sub-program projected expenditures in this case.

Q. What is Mr. Boutet's recommendation regarding Zonal Health Improvements in the LVD Lines Reliability sub-program?

A. On pages 14 and 15 of his direct testimony, Mr. Boutet states that the Company has provided more information about Zonal Health Improvements in the instant case than in Case No. U-21585, but he believes the Company's presentation is still insufficient. Mr. Boutet states that there is little discussion or analysis of the most cost-effective approaches to improve reliability. He states that the Reliability Analytics Engine ("RAE") is used to identify projects, but that it appears the RAE only ranks Zonal Health Improvement projects against each other rather than considering other potential solutions. Ultimately, he supports the Company's proposed test year investments, since they are largely in line with 2024 actual spending, but he recommends reducing bridge period investments to the same level, so that the Company works at the same pace as in 2024 while awaiting further support regarding the impacts of Zonal Health Improvements.

Q. Do you agree with Mr. Boutet's recommendation regarding the bridge period?

A. No. The RAE does not rank Zonal Health Improvement projects against one another. As stated on page 42, lines 10 through 15, of my direct testimony, the RAE simply ranks the *zones* themselves against each other, to help the Company identify where *some kind* of

System Average Interruption Duration Index ("SAIDI") reduction work is needed. As stated on page 42, lines 17 through 19, once the RAE has been used to identify zones with recent reliability challenges and with the most opportunity for improvement, only then does the Company develop and prioritize projects themselves. Pages 43, line 1, through 44, line 2, provide further detail about how the RAE is just one tool used in identifying projects. When a zone has a reliability issue, the Company believes that the problem is worth fixing so that customers experience fewer interruptions. The least-cost-best-fit approach is then used to identify the most cost-effective way of doing so, regardless of the specific approach ultimately selected.

In short, the Company uses the RAE as an input to identify zones needing improvement, and then uses multiple tools to compare a variety of potential solutions against one another before pursuing a Zonal Health Improvement project.

Q. Can you provide a more detailed illustration of how the Company selects Zonal Health Improvement projects from among alternatives?

A. In Exhibit A-226 (JMP-6), I am providing an illustrative example of an LVD concept approval. In this example, the Company identified an initial problem using zonal analysis. The Company then considered three different alternatives to address the problem. As shown, the Company ultimately selected the median-cost alternative for reasons given in the document. In other words, the Company considered multiple approaches to solve an identified problem and chose the least cost option that would resolve the issue.

Q. Do you have any other concerns with Mr. Boutet's recommendation?

A. I do not agree with Mr. Boutet's suggestion that Zonal Health Improvement work must stay level until the impacts of the work are better substantiated. As stated on page 47 of

my direct testimony, the Company has been doing this work since 2013. Clear benefits from Zonal Health Improvement projects are shown in Figure 23 in my direct testimony and on page 52, line 13, through page 53, line 10.

Q. What is Mr. Boutet's recommendation regarding the Repetitive Outages sub-program?

A. On page 16 of his direct testimony, Mr. Boutet performs a similar analysis as he did with CVR, noting recent years of underspending as compared with Company projections. Mr. Boutet recommends a 20% disallowance in the bridge period and test year as a compromise between the recent underspending and the importance of the work in meeting the Commission's CEMI-4 standard.

Q. Do you agree with this recommendation?

A. No. Mr. Boutet's approach is flawed to the extent that it assumes that the amounts spent in 2023 and 2024 necessarily dictate what will be spent in the future. The Company is providing year-to-date spending for this sub-program through September 2025 in Exhibit A-219 (MPK-29). Exhibit A-219 MPK-29, line 5, shows that, through September 2025, the Company has spent well over $6.3 million year-to-date, with spending of approximately $1.0 million and $1.1 million in August and September, respectively, and the Company is on track to invest over $11.2 million in 2025 based on the rate of increase.

Q. What is Mr. Boutet's recommendation regarding the Make-Ready investment category in the LVD Asset Relocations sub-program?

A. On pages 17 through 19 of his direct testimony, Mr. Boutet calculates that the Company's unit costs for Make-Ready work are increasing by nearly 60% compared to approved spending levels in Case No. U-21585. Mr. Boutet contends that the Company has not given

an explanation for why unit costs increased when the types of work seem to be constant. He recommends a disallowance based on using unit cost levels implied in Case No. U-21585.

Q. Do you agree with this analysis?

A. No. In the Make-Ready investment category, the Company typically recovers a percentage of the cost from the attaching third party, and both the projected spending in Figure 16 in my direct testimony and the historical costs in Exhibit A-130 (MPK-20), page 2, line 40, reflect the Company's costs net of that recovery amount. However, the Company's net costs do not reflect the full cost of the work. The unit cost should be evaluated based on the total cost of the work, rather than the Company's responsibility alone for Joint Attachment requests. This is important because, although the recovery amount is usually consistent from year to year, there are outliers. Typically, the Company has recovered 46-48% of Make Ready costs from attaching parties, which the Company expects to continue in future years. However, in 2023, customer contributions unusually offset 65% of spend due to a temporary increase in reimbursement from attaching parties driven by extensive rural expansion. This made the Company's net 2023 unit cost appear artificially lower, and those 2023 net unit costs informed Case No. U-21585, which is what Mr. Boutet cites for his justification that 2023 unit costs should be used in the instant case.

However, all-in unit costs have been fairly steady since 2022, and that is what is projected to continue in the instant case. These costs increased in 2022 compared to earlier levels, driven largely by Covid-era rural digital expansion and supply constraints. This data is shown in Table 1 below.

TABLE 1
MAKE-READY WORK COST DATA

Year	Total Make Ready Spending	Customer Amount Recovered	CE Responsibility	Percent Recovery	Make Ready Orders Complete	Total Unit Cost	Unit Cost of CE Responsibility	
2020	$9,877,759	$4,514,790	$5,362,969	46%	752	$13,135	$7,132	Actual
2021	$12,377,903	$5,924,557	$6,453,346	48%	829	$14,931	$7,784	Actual
2022	$27,879,164	$13,305,056	$14,574,108	48%	1236	$22,556	$11,791	Actual
2023	$37,496,781	$24,474,069	$13,022,712	65%	1655	$22,657	$7,869	Actual
2024	$39,574,196	$19,151,261	$20,422,935	48%	1640	$24,131	$12,453	Actual
2025	$64,779,696	$31,349,035	$33,430,661	48%	2685	$ 24,131	$12,453	Forecasted
2026	$75,334,047	$36,456,634	$38,877,413	48%	3122	$24,131	$12,453	Forecasted
2027	$79,594,168	$38,518,248	$41,075,921	48%	3298	$24,131	$12,453	Forecasted

Q. What is Mr. Boutet's recommendation regarding right-of-way ("ROW") spending in the LVD Lines Reliability sub-program?

A. On page 20 of his direct testimony, Mr. Boutet contends that the Company has not supported its projected test year spending level for ROW. He notes that the Company did not provide details about specific ROW projects but only stated that ROW costs are projected based on a percentage of Targeted Circuit Improvement spending. Because of this, he recommends that ROW spending be held to the level approved by the Commission in Case No. U-21585.

Q. Do you agree with this recommendation?

A. No. The Company provided additional explanation in a discovery response that Mr. Boutet has sponsored at Exhibit S-13.9. As stated in that response, the Company has consistently projected ROW costs as a percentage of Targeted Circuit Improvement spending, as these are correlated over the years. Since 2020, ROW costs have averaged 14% of Targeted Circuit Improvement spending, with a range from 11% to 19%. In the test year, the Company is only projecting ROW costs at 12% of Targeted Circuit Improvement costs, less than the recent average actual amount. ROW expenditures includes items such as

research prior to designs to understand the rights that the Company already has, as well as the creation of easement documentation for any new easements and payments for easements. The extent to which these costs apply to particular projects are typically not known until closer to project completion. Thus, the Company's projection based on a historical spending percentage represents a reasonable method for projecting these ROW costs.

ROW spending is increasing due to increases in the overall LVD Lines Reliability sub-program. Since Staff is largely supporting the Company's test year projections for the sub-program, the associated ROW costs should also be approved.

II. REBUTTAL OF STAFF WITNESS SCHILLER

Q. What is Ms. Schiller's recommendation regarding the LVD Lines Demand Failures sub-program?

A. Based on several responses to discovery, included in Exhibit S-19.0, Ms. Schiller states concern that the Company is not appropriately categorizing the costs associated with inspections in the LVD Lines Demand Failures sub-program, particularly as it relates to Security Assessments. On page 6 of her direct testimony, she suggests that these inspection costs, currently capitalized, should more properly be treated as operating expenses. In the next rate case, she recommends that the Company (1) provide a breakdown of inspection costs across the capital programs/subprograms; (2) support the classification of costs that are capitalized instead of expenses with reference to accounting guidance; and (3) amend the classifications, as necessary.

Q. Do you agree with this recommendation?

A. While the Company does not believe its current categorization policies are improper, the Company will not contest this recommendation. In its next rate case, the Company will

review its capitalization policies around line inspections and security assessment work on the distribution system in line with Ms. Schiller's proposal, and propose any necessary changes.

III. REBUTTAL OF STAFF WITNESS EVANS

Q. What is Mr. Evans' recommendation regarding the Company's proposed tariff changes for new service connection fees?

A. On pages 15 and 16 of his direct testimony, Mr. Evans reviews the Company's proposed tariff changes related to new service connection fees and indicates that Staff agrees with the Company's overall plan to update fees, and to begin charging a fee for new overhead service connections. However, Staff does not agree with the Company's proposal to use flat fees of $1,300 for all new residential services and $2,200 for all new general services. Mr. Evans recommends that the Company continue to use a fee structure with a per-foot component, particularly so that customers with shorter-than-average new services are not subsidizing customers with longer-than-average new services.

Q. Do you agree with this recommendation?

A. No, for several reasons. First, a significant portion of installing a new service involves fixed costs associated with the crew being onsite to do the work, and those fixed costs are included in the Company's proposed fee structure.

Second, the Company already charges a flat fee of $350.00 for new residential underground services up to 150 feet, as stated in section C6.2B(3) of the Company's tariff.

Third, flat fees create billing efficiencies that benefit both the customer and the Company. With a flat fee, the customer can pay earlier in the process and be done after that payment, rather than needing to wait for a full design to be developed. It also prevents

the need for any rebilling if the actual footage differs from what is originally quoted. Overall, the customer experience is improved with a flat fee.

Finally, it is worth noting that the Company's tariff proposal in the instant case provides for a flat fee in most cases. However, the flat fee is predicated on the customer accepting the Company's proposed route, which will generally be the shortest reasonable route, and the most cost-effective one. If a customer opts for a different route, then the customer will be assessed any additional costs incurred by the Company in addition to the flat rate. This protects other customers from subsidizing routes for a given customer that are unnecessarily long or expensive.

IV. REBUTTAL OF AG WITNESS COPPOLA

Q. What is Mr. Coppola's recommendation regarding capital investment in the LVD Lines New Business sub-program?

A. On pages 16 and 17 of his direct testimony, Mr. Coppola states that the Company's forecasted number of new service connections is reasonable, but that the unit cost is high since unit costs declined from 2023 to 2024 and the Company is now using a higher unit cost for the bridge period and test year. He recommends that the decline from 2023 to 2024 ought to be sustained going forward, and proposes disallowances based on holding unit costs at 2024 levels, plus inflation.

Q. Do you agree with this recommendation?

A. No. Mr. Coppola's use of one year of historical data to calculate unit costs is not consistent with his proposed methodology in much of the rest of this case. For example, Mr. Coppola proposes to use three-year historic average unit costs for the vintage underground cable rejuvenation investment category and the Repetitive Outages sub-program. The three-year historical average unit cost in the LVD Lines New Business sub-program is $13,319.

Applying Mr. Coppola's 2.9% inflation rate for the bridge period would yield a unit cost of $13,705, and applying his 2.4% inflation rate for the test year would yield a unit cost of $14,033. These bridge period and test year unit costs based on a three-year average are higher than the unit costs Mr. Coppola applied based only on 2024 actual.

Regarding Mr. Coppola's assertion that the decline in costs from 2023 to 2024 should be sustained, that is not necessarily true. As described on page 12, line 19, through page 13, line 2, of my direct testimony, the Company is proposing a tariff change that will lead to an increase in the number of customers opting for underground services, which will have the impact of increasing unit costs.

Q. Does Mr. Coppola make any other recommendations regarding the LVD Lines New Business sub-program?

A. On pages 18 and 19 of his direct testimony, Mr. Coppola expresses concern that the Company's contractor costs for this sub-program are significantly higher than in-house costs. He recommends that, in the Company's next rate case, the Company should outline how this gap to contractor costs can be reduced, or else the Company should bring more work in-house.

Q. How do you respond to this?

A. The Company is not opposed to further study of this issue. It should be noted that the Company's in-house workforce is only so large, and in some cases, as with unplanned customer-driven work, the Company must rely on contractors to get new customers connected in a timely manner if Company employees are engaged in other critical projects, such as reliability work.

Q. What is Mr. Coppola's recommendation regarding the LVD Asset Relocations sub-program?

A. On page 20 of his direct testimony, Mr. Coppola takes issue with the Company's projection for the Customer-Requested and Other Internal Relocations investment category. He claims that the Company has not provided justification for increased investment above the recent historical levels of work in this category. He notes that Exhibit A-166 (JMP-1), page 1, and Exhibit A-167 (JMP-2), page 1, only show a fraction of the number of projects that the Company is projecting. He recommends a disallowance that keeps the number of projects in this investment category at the three-year average.

Q. Do you agree with this recommendation?

A. No. Mr. Coppola is incorrect to compare projected units in Customer-Requested and Other Internal Relocations to the project lists in Exhibit A-166 (JMP-1), page 1, and Exhibit A-167 (JMP-2), page 1. These exhibits are only related to the LVD Underbuild investment category, so there should be no expectation that they tie to the numbers of a different investment category.

The Company's rationale for its projected growth in this investment category is discussed on page 34 of my direct testimony. In particular, the growth rate was derived based on the actual 3.2% growth rate from 2020 through 2023.

Q. Does Mr. Coppola address any other parts of the LVD Asset Relocations sub-program?

A. On pages 21 and 22 of his direct testimony, Mr. Coppola expresses concern over the Company's projected growth of the Make-Ready investment category. He proposes bridge

period and test year disallowances based on a 37% growth rate from recent actuals, arguing that this is the only growth rate supported by data provided by the Company.

Q. Do you agree with this recommendation?

A. No. The Company provided additional support for its projections in a discovery response to Staff (discovery response 21870-ST-CE-0078), which I am providing as Exhibit A-225 (JMP-5). The first thing to note in this response is that the Company corrected its projected bridge period and test year units in the discovery response; on page 21, lines 4 through 7, of his direct testimony, Mr. Coppola is still using the original uncorrected numbers.

The table on the second page of this discovery response shows the Company's calculations for projected growth in Make-Ready work. The projected growth in federal broadband funding is based on information published by the federal government, and the Company has calculated the annual growth rates of this work. In order to provide additional assurance that these numbers are not over-projected for 2025 or 2026, particularly issues that can be created by timing issues with federal funding, the Company applied a 20% discount to the 2025 and 2026 growth rates, making the Company's numbers more conservative. Mr. Coppola is incorrect to assert that this response does not show the Company's calculations and he is incorrect to assert that the Company has not supported its projections.

Beyond the question of unit growth, Mr. Coppola's calculations on page 22 of his direct testimony are incorrect because he did not use the Company's updated Figure 16 as provided in Exhibit A-225 (JMP-5), and thus did not use the correct unit cost for his calculations. The Company's projected unit cost is not $5,955, but rather is approximately

$12,300. This is discussed in my rebuttal to Mr. Boutet. Mr. Coppola's proposed disallowances should not be adopted.

Q. What is Mr. Coppola's recommendation regarding the Zonal Health Improvements investments in the LVD Lines Reliability sub-program?

A. On pages 24 and 25 of his direct testimony, Mr. Coppola notes that unit costs may have been skewed in 2022 and 2023 by high amounts of fusing work, which was much reduced in 2024. Therefore, he argues that 2024 unit costs are a reasonable baseline to use, and he notes that apparent bridge period unit costs are approximately double and test year unit costs are nearly triple. He argues that this increase is not supported, and recommends disallowances based on remaining at 2024 unit costs plus inflation, amounting to reductions of $27.3 million in the bridge period and $22.6 million in the test year.

Q. Do you agree with this recommendation?

A. No. Zonal Health Improvements encompass a very diverse portfolio of projects, and indeed defining a number of units for the entire portfolio of Zonal Health Improvement projects is difficult to do. See the footnote to Figure 35, page 69, in my direct testimony, which notes that the 497 bridge period units and the 175 test year units just reflect the number of line items in Exhibit A-166 (JMP-1) and Exhibit A-167 (JMP-2).

A review of these two exhibits will show the diversity not only of projects, but of the types of actual underlying units as well. Exhibit A-167 (JMP-2), pages 3 through 5, shows that some line items simply indicate "1 project," while others are based on addressing a certain amount of line miles, and some are defined by addressing a certain number of poles, and still others continue to involve a certain number of fuses. It is not reasonable to try to reduce this to a single unit cost by dividing the total investment level

for Zonal Health Improvements by the number of line items in an Excel file. A similar issue is shown on Exhibit A-166 (JMP-1), pages 3 through 11.

Unit cost analyses can only possibly be valuable if the dividends and divisors are correctly set. Disregarding the actual units provided in Exhibits A-166 (JMP-1) and A-167 (JMP-2), and simply dividing by the number of Excel rows, does not provide a useful unit cost analysis, and the Commission should not adopt such an analysis as a basis for cost disallowances for these projects.

Q. What is Mr. Coppola's recommendation regarding voltage conversions?

A. On pages 25 through 27 of his direct testimony, Mr. Coppola states that the Company's response to discovery request 21870-AG-CE-0346 indicates that the Company's test year units are actually only 165, instead of the 283 that are shown in Figure 35 of my direct testimony. He then takes issue with the Company's unit costs compared to 2024 actuals, and recommends bridge period and test year disallowances based on this (and using 165 units as the multiplying factor for this test year calculation), amounting to reductions of $2.267 million in the bridge period and $9.462 million in the test year.

Q. Do you agree with this recommendation?

A. No. Mr. Coppola is incorrect to use 165 as the number of units for the test year. In discovery request 21870-AG-CE-0346, the Attorney General asked the Company to provide calendar year spending projections for voltage conversions even though the instant case is not based on a bridge period or test year that align with a calendar year. Providing calendar year projections can create misalignments with what is actually included in the test year, since work does not necessarily take place on a uniform basis month-to-month. Exhibit A-167 (JMP-2), page 2, provides the Company's actual workplan for the test year,

and it shows 283 miles of work, which is the correct unit to use for the test year. When 283 is used as the divisor, the Company's test year unit cost is $117,014 per mile, which is in fact lower than the actual unit cost for 2024. Therefore, Mr. Coppola's recommended test year disallowance is without merit.

Q. What is Mr. Coppola's recommendation regarding underground cable rejuvenation?

A. On pages 27 and 28 of his direct testimony, Mr. Coppola argues that the Company's unit costs for this work are excessive, and calculates a projected bridge period and test year spending level based on a three-year average of actual unit costs, recommending a disallowance of $16.616 million in the bridge period and $39.120 million in the test year.

Q. Do you agree with this recommendation?

A. No. Mr. Coppola appears to have obtained the Company's 2021 through 2024 unit costs from discovery response 21870-AG-CE-0346, Attachment 1, which included the following data.

TABLE 2

	2021		2022		2023		2024	
	Cost	**Units**	**Cost**	**Units**	**Cost**	**Units**	**Cost**	**Units**
Underground Cable Rejuvenation	$1,672,800	10	$1,123,300	5	$997,300	11	$3,545,900	21

Mr. Coppola's proposed disallowances rely on a comparison of this data to the data provided in Figure 35 in my direct testimony. However, this is not an apples-to-apples comparison. The data shown in Table 2 above is using projects as a unit, whereas Figure 35 in my direct testimony is using miles. Using miles for 2021 through 2024, the data would have shown as follows.

TABLE 3

	2021		2022		2023		2024	
	Cost	Miles	Cost	Miles	Cost	Miles	Cost	Miles
Underground Cable Rejuvenation	$1,672,800	2.67	$1,123,300	3.14	$997,300	2.01	$3,545,900	3.53

Using these numbers, the Company's four-year average unit cost has been $646,720, meaning the Company is actually proposing to do work in the bridge period and test year at a lower unit cost than recent actuals. Given the ramp-up in work (for which Mr. Coppola indicates support), the Company expects to realize some efficiencies.

Q. What is Mr. Coppola's recommendation regarding ROW costs for LVD?

A. On page 29 of his direct testimony, Mr. Coppola claims that the Company has not supported its increased ROW projection for the test year and recommends that it be set instead at 2024 levels, which he notes was the highest level of the past four years. This results in a test year reduction of $11.465 million.

Q. Do you agree with this recommendation?

A. No. The Commission should reject Mr. Coppola's recommendation for the same reasons given in my response to Mr. Boutet above.

Q. What is Mr. Coppola's recommendation regarding the Resiliency sub-program?

A. On pages 30 through 37 of his direct testimony, Mr. Coppola reviews the Company's proposed investment in overhead to underground conversions ("OHUG") and in the ELGE-MIEJ Undergrounding Secondary and Services work. Company witness Kelly is providing the rebuttal to Mr. Coppola for most of this, but I will address some of Mr. Coppola's assertions about OHUG selection criteria.

Q. What position does Mr. Coppola take regarding OHUG selection criteria?

A. On pages 31 and 32 of his direct testimony, Mr. Coppola notes that the Company changed its selection criteria between its proposal in Case No. U-21585 and its proposal in the instant case. Because of this, he claims that the Company "is still struggling to find an effective approach that adequately justifies undertaking the overhead to underground conversions."

Q. How do you respond to this?

A. I do not agree. By saying that the Company "is still struggling," Mr. Coppola is incorrectly implying that the Company is making dramatic changes as though this will result in the Company stumbling upon an effective solution. At no point has the Company been "struggling" in this area. The initial pilot proposed and approved in Case No. U-21389 had certain selection criteria for projects, which also informed the Company's proposal in Case No. U-21585 to continue undergrounding work through 2025 and into 2026. The Commission did not approve that request in Case No. U-21585 in order to allow the pilot to be completed so that lessons could be learned and applied. In the instant case, the Company has made modest revisions to its selection criteria precisely to account for those lessons learned. The changes are modest. For example, the Company increased the upper limit on an eligible zone from 100 to 200 customers because of concerns expressed in the pilot that too many customers would be excluded. The Company adjusted its criterion regarding tree cover to specifically focus on zones with recent tree- or weather-caused outages, in order to zero in on zones that are currently dealing with these issues that justify OHUG work.

Q. What is Mr. Coppola's recommendation regarding the LVD Lines Capacity sub-program?

A. On pages 37 through 39 of his direct testimony, Mr. Coppola analyzes this sub-program primarily through the lens of discovery response 21870-AG-CE-0357, which he has included in Exhibit AG-7. In that discovery request, the Attorney General asked if the Company's LVD Lines Capacity investments were exclusively directed at circuits with over 140% overload. In his direct testimony, Mr. Coppola seems to reason that circuits with over 140% overload are the only ones that should be addressed, and that any overload lower than that level is "less risky" and that apparently all investments directed at such overloads are unnecessary and can be deferred. Mr. Coppola recommends removing capital expenditures for projects with overload of less than 140%, resulting in removal of $5.375 million in the bridge period and $40.911 million in the test year.

Q. Do you agree with this recommendation?

A. No. As noted in my response to Mr. Boutet, the Company is not opposing Staff's proposed adjustment to the test year, but Mr. Coppola's disallowance goes far beyond that proposed by Staff. As Mr. Boutet noted in his direct testimony, the Company's bridge period investments are aligned with what the Commission approved in Case No. U-21585, and it would be unreasonable to impose a disallowance on that already-approved amount when much of the period in question has already taken place with spending that the Commission already found reasonable and prudent.

Mr. Coppola states that assets overloaded to 100% through 139% are "less risky," but his analysis seems premised upon them being "low risk." While the former is a relative term, the latter is a more absolute one. An asset loaded to 135% of the manufacturer's

rating may be in a less risky position than one loaded to 145%, but that does not mean it is low risk and can be safely ignored. Manufacturer ratings are established to ensure safe and reliable operation of assets. Prolonged operation beyond these ratings, even by a small margin, accelerates deterioration and significantly increases the risk of failure. Mr. Coppola's recommendation reflects an unacceptable tolerance for allowing assets to operate well beyond manufacturer specifications for extended durations.

Furthermore, Mr. Coppola's analysis treats all assets as though they have equal risk levels at a given overload percentage. The Company agrees that the general categories provided in Figure 52 in my direct testimony did not capture the nuance related to differing risk levels associated with different types of equipment at a given overload percentage, I explained this in discovery response 21870-AG-CE-0357 and provided examples. For example, the response stated that isolators and conductors loaded anywhere above 100% face acute risk of failure. The response shows that a considerable amount of the planned investment in the test year in the "119% or less" category is for conductor and isolators, and isolators also make up a component of the "between 120%-139%" category. Mr. Coppola's proposal that the Company should not address these overloaded assets would result in the Company being particularly irresponsible to reliability and public safety.

Mr. Coppola's proposed disallowances should not be accepted by the Commission, which should instead accept the proposal of Mr. Boutet.

Q. What is Mr. Coppola's recommendation regarding LVD Transformers?

A. On page 40 of his direct testimony, Mr. Coppola argues that the Company has not supported its projected need for more 1-phase and 3-phase padmount transformers. In

particular, he notes that the primary driver of increasing need for these transformers is the Company's OHUG work, which he asks the Commission to disallow in full, which would obviate the need for as many of the transformers. He recommends that the Company's increased purchases of padmount transformers be held to their respective growth rates between 2023 and 2024, and proposes reductions in capital expenditures of $9.791 million in the bridge period and $11.777 million in the test year.

Q. Do you agree with this recommendation?

A. No. Most importantly, the Company does not agree with Mr. Coppola's recommendation to completely eliminate the Company's OHUG work, as described above and in Company witness Kelly's testimony. If the Company's OHUG plan is approved, then the transformers will be needed.

As Mr. Coppola's own calculations show, padmount transformer purchases were already increasing from 2023 to 2024, predating the initiation of substantial OHUG work, and indicating that other factors like new business work are in fact driving growth in transformer needs. Expansion of OHUG work will drive further growth, and the Company's projection should be approved.

Q. What is Mr. Coppola's recommendation regarding the Repetitive Outages sub-program?

A. On page 45 of his direct testimony, Mr. Coppola indicates support for the Company's projected volume of work in the Repetitive Outages sub-program, but takes issue with the bridge period and test year unit costs, stating that the Company has not supported the increase. He calculates a much lower unit cost based on a three-year historical average,

and proposes capital expenditure reductions of $14.246 million in the bridge period and $20.745 million in the test year.

Q. Do you agree with this recommendation?

A. No. Unit costs from 2023 and 2024 should not be assumed to represent expected costs going forward, since those two years included reduced work volumes and therefore would not necessarily have included the full range of work types that the sub-program will include when scaled up. Furthermore, I addressed the issue of increasing unit costs on page 79, line 11, through page 80, line 2, of my direct testimony. As discussed there, the Company is shifting investment to more robust, and more costly, hardening projects such as line relocation, undergrounding, and replacing bare wire with tree resistant wire. Accordingly, projecting costs based on historical averages will not accurately reflect expected future costs,

The Repetitive Outages sub-program is critical for achieving the Commission's CEMI-4 targets, and the Commission should approve the Company projection. If it does not, it should at least adopt Mr. Boutet's position, which is significantly more reasonable.

Q. Does Mr. Coppola have any other comments about Repetitive Outages?

A. On page 46 of his direct testimony, Mr. Coppola suggests there are insufficiencies with the information provided in my direct testimony and in Exhibit A-169 (JMP-4). He recommends that the Company, in its next rate case, provide "more pertinent information" about completed Repetitive Outage projects.

Q. How do you respond?

A. The Company believes that it provided information in Exhibit A-169 (JMP-4) that was in line with the Commission's guidance in its Order in Case No. U-21585. If the Commission

provides updated guidance in the instant case, the Company will be happy to comply with that guidance to the extent that the requested information is available.

Part of Mr. Coppola's concern is with the fact that some identified historical projects took place on circuits that had no outages in 2023 or 2024. It should be noted that Exhibit A-169 (JMP-4) lists projects that were completed in those two years, and that many of those projects would have been identified based on outages from 2021 or 2022.

V. REBUTTAL OF ABATE WITNESS YORK

Q. What is Ms. York's recommendation regarding the LVD Lines Rehabilitation sub-program?

A. On page 26 of her direct testimony, Ms. York notes that two investment categories with LVD Lines Rehabilitation, namely modem replacements and meter voltage anomalies, do not have specific identified projects. Ms. York argues that, because of this, the entire LVD Lines Rehabilitation sub-program should be held at the five-year average level. This results in capital expenditure reductions of $2.975 million in the bridge period and $5.078 million in the test year.

Q. Do you agree with this recommendation?

A. No. The Company has not historically provided a list of all modem replacement projects, since they are individually small and since there are 800 of them each year. In Case No. U-21585, for example, Exhibit A-128 (DAL-2), page 38, line 25, also simply indicated that 800 modems would be replaced for $2,998,000. In Case No. U-21585, this proposed spending was approved with no objection from any party. Meter voltage anomalies, while a new investment category in the instant case, are similar. As shown in Figure 45 in Exhibit A-129 (MPK-19), the meter voltage anomalies investment category involves several hundred individual small work locations each year, and the Company has treated this

similarly to modem replacements by not endeavoring to list out each individual location. In addition, I supported the need for the modem replacement and meter voltage anomaly projects at pages 84-85 of my direct testimony, and the basis for the projections on page 87 of my direct testimony.

Aside from that, it would also not be reasonable to broadly disallow the entire LVD Lines Rehabilitation sub-program expenditures, which contains other investment categories not discussed in Ms. York's testimony. The Commission should not remove all funding for these important projects.

Q. What is Ms. York's recommendation regarding the LVD New Business Capacity sub-program?

A. On page 27 of her direct testimony, Ms. York states that projected spending in LVD New Business Capacity sub-program is largely uncertain since it is customer-driven, and she notes that the Company has only identified bridge year projects to cover a part of the projected spending, and no test year projects. Because of this, she argues that spending in the sub-program should be held to the five-year historical average, which results in capital expenditure reductions of $11.958 million in the bridge period and $3.908 million in the test year.

Q. Do you agree with this recommendation?

A. No, for several reasons. First, in Case No. U-21585, the Company provided a similar level of detail in its project lists. In that case, Exhibit A-127 (DAL-1), page 49, line 50, indicated that the Company had identified bridge year projects in the amount of $8,727,000, out of a total bridge year projection for the sub-program of $23,903,000. The Company also identified no specific test year projects for LVD New Business Capacity in Case No.

U-21585. However, the Commission approved full recovery of the Company's projected spending, following no objection from any parties.

Second, the Company's recent actual spending in LVD New Business Capacity shows that using a five-year historical average would set the approved spending levels far too low. As shown in Exhibit A-95 (MPK-3), line 25, spending in LVD New Business Capacity has been steadily increasing every year and exceeded the five-year average in 2022, 2023, and 2024. Setting spending at the five-year average would return the Company to roughly 2021 levels when the sub-program has been demonstrably growing. Furthermore, while the Company had only identified bridge period projects of about one-third of the total bridge period projection in Case No. U-21585, the Company actually ended up spending even more than the total projected amount, as summarized in Table 4 below.

TABLE 4
LVD NEW BUSINESS CAPACITY SPENDING

	1/1/24-12/31/24
U-21585 Projection[1]	$20,511,000
Actual[2]	$33,430,000

As this table shows, the Company has had to respond to customer demand and invest in excess of its recent projections, indicating that anticipated growth is not uncertain or speculative.

Finally, the Company's year-to-date spending through September has been $18,881,217, as shown in Exhibit A-219 (MPK-29), line 8. Even a simple continuation of

[1] Refer to Case No. U-21585, Exhibit A-98 (MPK-6), line 4, column c. In Case No. U-21585, the bridge period covered 1/1/24-2/28/25, but the Company included a projection for the 2024 calendar year.
[2] Refer to the instant case, Exhibit A-113 (MPK-3), line 25, column g.

the current spending rate through the remainder of the bridge period would result in spending in excess of Ms. York's proposal, which highlights the unreasonableness of her recommendation that is based on uncertainty of spending (Exhibit A-219 (MPK-29) shows that the Company is on track to spend over $26 million just in the 2025 calendar year).

Q. What is Ms. York's recommendation regarding the LVD Transformers sub-program?

A. On page 28 of her direct testimony, Ms. York argues that the Company's projected growth in transformer demand, especially tied to new business and electric vehicle adoption, faces significant uncertainty. Because of this, she argues that it would be more prudent to simply hold spending at 2024 actual levels, which she believes would capture some of the recent growth in demand while recognizing the uncertainty. This results in capital reductions of $105.077 million in the bridge period and $84.896 million in the test year.

Q. Do you agree with this recommendation?

A. No. First, as discussed on page 137 of my direct testimony, the growth in overall LVD Transformers spending is driven primarily by growth in purchases of 1-phase and 3-phase padmount transformers, driven in turn by undergrounding work, by general new business activity, and by projected electric vehicle ("EV") adoption. Undergrounding work is not uncertain; the Company has a clear plan for undergrounding backed by many specific projects. While ABATE witness Fitzhenry argues that the Company should not engage in undergrounding, the rebuttal testimony of Company witness Kelly explains why his analysis is incorrect. And as discussed above in response to Mr. Coppola, factors like new business work are in fact driving growth in transformer needs. The Company's basis for growth in LVD Transformers is well-substantiated.

Additionally, the Company is not purchasing transformers simply to build up its inventory. As alluded to on page 83 of Exhibit A-129 (MPK-19) and on pages 137 and 138 of my direct testimony, due to acute supply chain disruptions in the transformer industry during the early 2020s, utilities experienced significant backlogs in procuring essential equipment. In response, the Company has had to fundamentally alter its procurement strategy. Whereas the Company previously ordered materials incrementally — typically covering only a few months of anticipated demand — it is now compelled to place full-year orders upfront. This shift is driven by both historical procurement challenges and the increased variability in future forecasts, making it prudent to secure appropriate quantities as a hedge against ongoing supply risks and support the Company's Reliability Roadmap.

Finally, the Company's year-to-date spending of $134,287,313 in the LVD Transformers sub-program, as given in Exhibit A-219 (MPK-29), line 3, shows the Company is on pace to exceed the 2025 bridge period projection.

Q. What is Ms. York's recommendation regarding the LVD Asset Relocations sub-program?

A. On page 29 of her direct testimony, Ms. York states that the Company has only identified projects in the bridge period and test year that represent a small amount of total projected spending for the sub-program. She asserts that the remainder of the spending is highly uncertain, since it is driven by external parties, and she particularly notes that customer requests are sometimes tied to home remodeling work, which have slowed due to interest rates since 2023. Because of this, she recommends that LVD Asset Relocations spending

be held at 2024 actual levels. This reduces capital expenditures by $46.409 million in the bridge period and $27.587 million in the test year.

Q. Do you agree with this recommendation?

A. No. Please see my discussion of similar issues above in my response to Mr. Coppola. The Company has, for a number of years, provided project lists only for LVD Asset Relocation projects tied to the Company's own High Voltage Distribution ("HVD") projects, since these are known to the Company in advance. While home remodeling projects can impact requested relocations as noted on page 37 of my direct testimony, page 29, line 20, through page 30, line 13, of my direct testimony lists a large number of activities that can drive external requests.

Customer-requested work is only one part of the LVD Asset Relocations sub-program, and growth in customer-requested work only makes up a small part of projected growth in LVD Asset Relocations. See Exhibit A-130 (MPK-20), line 38, for recent history of customer-requested work specifically. The Company projected growth for customer-requested work using the methodology explained on page 34 of my direct testimony. However, much more of the projected growth in LVD Asset Relocations is tied to growth in make-ready work[3], which is explained on page 33, line 10, through page 34, line 5, of my direct testimony. Additional details on make-ready work growth were provided in discovery response 21870-ST-CE-0078, which is provided as Exhibit A-225 (JMP-5), and were described above in my response to Mr. Coppola.

[3] Refer to Exhibit A-130 (MPK-20), line 40, for recent history of make-ready work specifically, and compare to projected amounts in Figure 16 of my direct testimony.

VI. REBUTTAL OF ABATE WITNESS FITZHENRY

Q. What is Mr. Fitzhenry's recommendation regarding pole replacements in the LVD Lines Reliability sub-program?

A. Beginning on page 12 of his direct testimony, Mr. Fitzhenry discusses the Company's pole replacement plan. He says that, while the Company agreed with the Liberty's recommendation to place less emphasis on asset age when deciding to replace assets, it appears to him that the Company is relying solely on age when determining how many poles will be rejected and slated for replacement during inspections. He cites the Company's Reliability Roadmap, which shows a breakdown of LVD by poles with assumed rejection rates. He recommends that a 5% rejection rate be used instead of the Company's rejection rate assumptions, which would reduce the Company's investment in pole replacements by 50%, and cites the example of Midwest Energy, which saw such a rejection rate on its system. This results in capital reductions of $63.750 million in the test year.

Q. Do you agree with this recommendation?

A. No. First, the Company is not proposing to use age as the deciding factor in replacing LVD poles. Poles will only be replaced if they are rejected according to NESC criteria following inspection. But it is not the Company's understanding that Liberty advocated ignoring age in developing strategies or assumptions about the likely state of the system, with those assumptions to be validated by inspection. In developing a pole replacement plan, the Company needed to create a reasonable estimate of how many rejected poles were likely on the system. Age is a reasonable proxy in developing this kind of analysis, since age is correlated with deterioration of the wood.

The Company did not arrive at 10% arbitrarily. The Company's assessment of the likely average condition of poles of given vintages was based on research conducted by the Electric Power Research Institute ("EPRI"). The results of this research were provided to ABATE as discovery response 21870-AB-CE-0712, and I am sponsoring this as Exhibit A-227 (JMP-7). EPRI's research considered data from multiple utilities. It shows that the rejection rate of poles steadily increases with age. This informed the Company's assumptions about the likely rejection rates of different pole vintages on its own system.

EPRI's research is more robust than looking at a single utility in Kansas that has a much smaller system than that of the Company. Indeed, it is not clear why Mr. Fitzhenry chose Midwest Energy as his only point of comparison. However, he presents no other information about Midwest Energy that would allow us to determine if they are a reasonable proxy of the Company's system, and it would be imprudent to rely on a single data point in this analysis when more comprehensive resources are available.

Q. What is Mr. Fitzhenry's recommendation regarding underground cable rejuvenation?

A. Mr. Fitzhenry, on pages 15 and 16 of his direct testimony, recommends that the Commission disallow test year investments in underground cable rejuvenation above what is in the bridge period, and that the Commission should specifically strike it from the Investment Recovery Mechanism ("IRM"). Mr. Fitzhenry contends that underground cable rejuvenation does not provide immediate safety or reliability benefits, because the line is already underground. He argues that rejuvenation can "only provide future benefits in the event that an existing underground cable fails."

Q. Do you agree with this recommendation.

A. No. Mr. Fitzhenry's logic is not sound. Investments in the Demand Failures program address situations where an asset has already failed. Any investment in the Reliability program is, to some extent or another, proactive; the Company is making an investment today in order to prevent an outage in the future. Consider the aforementioned pole replacement plan: a rejected pole is still standing and supporting the conductor, and may continue to do so for some period of time. But the Company replaces it rather than waiting for it to completely fail. We would not say that the pole replacement provided no benefit, because a likely future outage is prevented. Similarly, underground cable rejuvenation targets cable that is starting to deteriorate even if it has not failed yet. The Company does not believe that assets should be run to failure, and does not believe that benefits only accrue to customers if the utility restores them from an active outage, when the work would be more expensive and when customers would have to deal with an interruption to service.

Additionally, as noted on page 60 of my direct testimony, Liberty concluded that underground cable rejuvenation is a sound means of addressing reliability issues, and that the Company has had success with it to date.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Thank you. Next is company witness Daniel A. Schmoekel. Mr. Schmoekel's direct testimony consists of a cover page and 45 pages of questions and answers. He also had rebuttal testimony consisting of a cover page and three pages of questions and answers, and his -- his only exhibit is his schedule, Exhibit A-12.

THE COURT: All right. Are there any objections to the admission of this testimony?

Hearing none. The direct and rebuttal testimony of Daniel Schmoekel is bound into the record.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

DANIEL A. SCHMOEKEL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Daniel A. Schmoekel, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed as Senior Strategy Manager for Electric Distribution for Consumers Energy Company ("Consumers Energy" or the "Company"). In that capacity, I am responsible for developing prioritized plans in alignment of Company goals for improvement of electric assets, safety, and compliance.

Q. What is your educational background?

A. I graduated from Michigan Technological University with a Bachelor of Science Degree in Civil Engineering in 2006. In addition, I graduated from Grand Valley State University in 2018 with a Master of Business Administration degree. I earned a Professional Engineering license (State of Michigan) in 2011, and achieved certification as a Project Management Professional (Project Management Institute) in 2013.

Q. Please describe your business experience.

A. Following graduation from Michigan Technological University, I worked as an engineer at OHM Advisors (Livonia, Michigan) until 2008. In 2008, I joined Consumers Energy as a project engineer responsible for capital improvement projects at the B.C. Cobb Generating Facility ("Cobb"), a now-retired, five-unit power plant located in Muskegon, Michigan. In 2010, I accepted a position as a Mechanical Maintenance Supervisor at Cobb, where I was responsible for establishing the work schedule and prioritizing work assignments for mechanical maintenance personnel, as well as ensuring policies and practices of the Working Agreement were followed. In 2011, I accepted a position as a

System Owner at the J.H. Campbell Complex ("Campbell") in West Olive, Michigan, a three-unit coal-fired generating facility. As a System Owner, my responsibilities included providing engineering and technical direction to identify and correct operational, design, and maintenance related issues. I was then promoted to Production Engineer at Campbell Unit 3, where I monitored plant operating parameters and identified/investigated equipment deficiencies. In 2015, I was promoted to Production Lead at Campbell Unit 3. In this position, I ensured interim acceptance of all Campbell Unit 3 Air Quality Control Systems related equipment per applicable Consumers Energy policies and procedures, performed technical reviews of system operating procedures/new equipment modification designs, and managed the Operating and Maintenance and capital budgets for the Campbell Unit 3 Operations Department. In 2018, I transferred to the Operations, Finance, and Planning organization as the Electric Dispatch Principal Team Lead. In this role, I had operational responsibility for Low Voltage Distribution dispatching and management of the planning and scheduling functions of short cycle streetlight work orders for 30 Headquarters across Consumers Energy's electric service territory. In October 2021, I accepted the role of Manager of Streetlight Programs. In this role I oversaw billing reconciliations, asset management, and contracts, and managed budgets for street lighting programs. In March 2023, I was promoted to Asset Strategy Manager (and then promoted to Senior Strategy Manager in July 2023). In this role, I develop prioritized plans in alignment with Company goals for improvement of electric assets, and safety and compliance.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony in the Company's 2022, 2023, and 2024 Electric Rate Case Nos. U-21224, U-21389, and U-21585, respectively.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Streetlight Program requests in this case. Toward that end I will:

- Describe Consumers Energy's streetlighting assets and provide an overview of the Company's strategic plan for management of those assets. Aspects of the strategic plan include streetlighting outage restoration performance, accelerated/planned conversions, streetlighting resources, planned maintenance, and customer outage reporting;

- Support the reasonableness and prudence of the capital expenditures for the conversion of overhead-fed cobrahead streetlights for the historical year ended December 31, 2024, the 16-month bridge period beginning January 1, 2025, and ending April 30, 2026, and the projected test year beginning May 1, 2026, and ending April 30, 2027;

- Support the reasonableness and prudence of the capital expenditures for the conversion of high intensity discharge ("HID") overhead-fed cobrahead streetlights that are located in the vicinity of failed overhead-fed cobrahead fixtures for the historical year ended December 31, 2024, the 16-month bridge period beginning January 1, 2025, and ending April 30, 2026, and the projected test year beginning May 1, 2026, and ending April 30, 2027;

- Support the reasonableness and prudence of the capital expenditures for the installation of new customer-requested streetlighting assets for the historical test year ended December 31, 2024, the 16-month bridge period beginning January 1, 2025, and ending April 30, 2026, and the projected test year beginning May 1, 2026, and ending April 30, 2027; and

- Discuss the Company's streetlight outage restoration performance.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into the following sections.

I. Consumers Energy Company-owned Streetlight Assets

II. Consumers Energy Plan for Streetlights

III. Streetlight Outage Reporting and Restoration

IV. LED Streetlight Equivalency Evaluations and New Business

V. Conversion of Cobrahead, Post Top, and Center Suspension Streetlights

VI. Planned Streetlight Conversions

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Michael P. Kelly sponsors the operations and maintenance ("O&M") expense associated with operating the streetlighting program, whereas I will be supporting the capital expenditures associated with operating the streetlighting program.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (DAS-1)	Schedule B-5.9	Summary of Actual and Projected Electric Capital Expenditures for the Years 2020 through 2027.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

I. CONSUMERS ENERGY COMPANY-OWNED STREETLIGHT ASSETS

Q. Please provide an overview of the Company's streetlight assets.

A. The Company owns and maintains approximately 173,000 streetlights. The majority of these streetlights are cobrahead fixtures (see Figure 1 below). In addition to the 119,000 cobrahead fixtures, the Company has approximately 11,000 center suspension streetlights and approximately 43,000 post-top fixtures, which make up the total quantity of 173,000 streetlights.

FIGURE 1
COBRAHEAD FIXTURE WITH LIGHT EMITTING DIODE



The streetlights the Company owns primarily fall in one of two buckets: HID and light emitting diode ("LED").

HID luminaires include mercury vapor ("MV"), high pressure sodium ("HPS"), and metal halide ("MH"). The MV, MH, and LED streetlights typically have a similar color temperature (white light) whereas the HPS streetlights typically have an amber color.

Q. Is the HID technology obsolete?

A. Not entirely. Pursuant to the Energy Policy Act of 2005,[1] the MV technology has been discontinued and is obsolete. As I will discuss later in this testimony, the Company has taken a planned conversion approach to replacing the MV technology. Manufacturers are discontinuing HID offerings and the Company is replacing HPS technology for cobrahead, post top, and center suspension fixtures. The continuously evolving LED technology is far more energy efficient than any of the available HID technologies.

[1] PL 109-58; 119 Stat 631. See Section 135.

II. CONSUMERS ENERGY'S PLAN FOR STREETLIGHTS

Q. Please provide an update on the Company's continuing efforts to improve its streetlighting service.

A. As I will discuss later in this direct testimony, the Company has engaged additional resources, implemented its Streetlight Outage and Restoration ("SOAR") application, completed a streetlight patrol and fix initiative, completed an initiative for advanced lighting controls, and developed a modified conversion plan for its HID cobrahead and post top fixtures—all to support improved outage restoration performance.

Q. How has the Company collaborated with its stakeholders in arriving at some of the program improvements?

A. The Company has continuously supported interaction with its customers, including the Michigan Municipal Association for Utility Issues ("MI-MAUI"), in developing its streetlighting improvements. The Company met with MI-MAUI seven times in 2024 to discuss streetlighting reliability reporting, and operational progress to identify opportunities for improvement and enhance customer experiences. Throughout the collaborative process, the Company has been receptive to suggestions for process improvements.

Q. Does the Company plan to continue its collaboration with its stakeholders to identify future program improvements?

A. Yes. Consistent with the Commission's suggestion in Case No. U-20963 to continue to collaborate with MI-MAUI and other parties to address streetlighting concerns, the Company and MI-MAUI continue to meet bi-monthly to discuss relevant street lighting topics.

Q. Was streetlighting reliability a topic in the MPSC electric distribution audit in Case No. U-21305?

A. No. Streetlighting reliability was not a topic in Case No. U-21305

Q. Does the Company have a long-term plan documented for improving the reliability of its streetlights?

A. Yes. The ideal state for the Company's streetlight program is to repair or replace streetlights only at the end of the component lifecycle, rather than having to replace components that fail early. Extending the lifecycle of the luminaire reduces repair expenses across the Company's streetlight portfolio. The Company has documented its streetlight reliability plan in the Reliability Roadmap. Please see Exhibit A-129 (MPK-19), for the Company's latest version of the Reliability Roadmap.

III. STREETLIGHT OUTAGE REPORTING AND RESTORATION

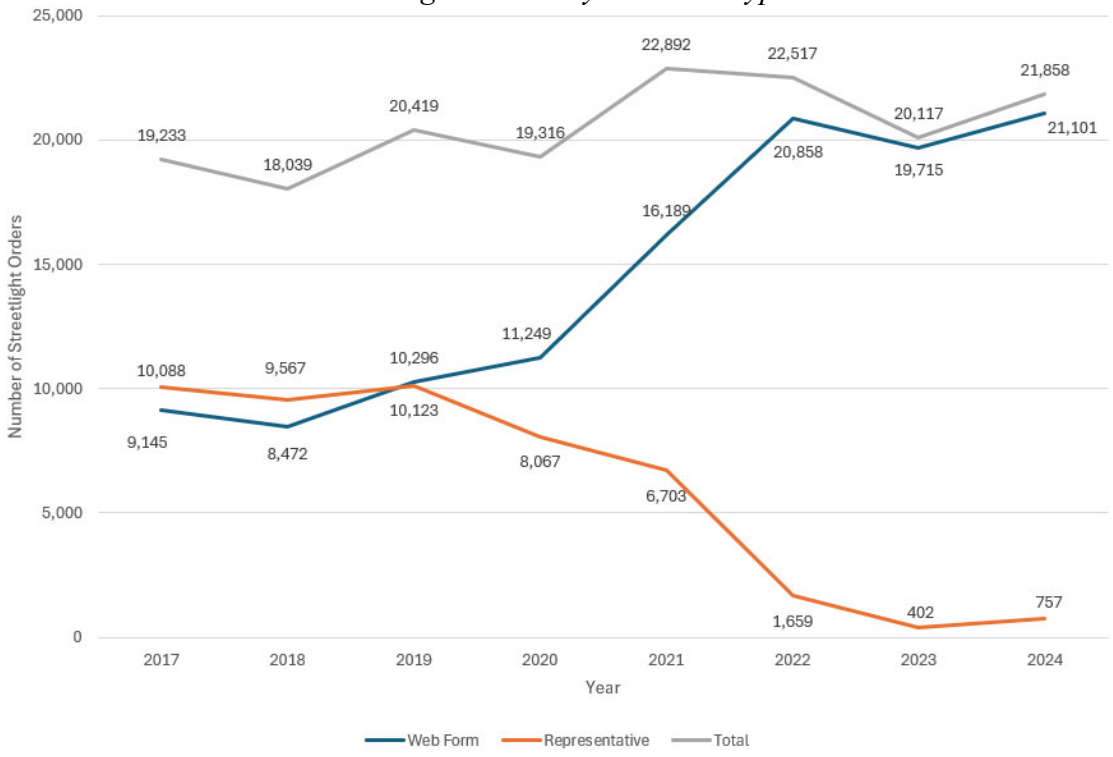
Q. What actions has the Company taken to improve streetlight outage performance?

A. In 2022, the Company initiated a proactive plan to convert HID cobrahead streetlights located in the vicinity of failed cobrahead streetlights to LED because every proactive conversion eliminates a future HID streetlight outage. In 2024, 478 HID cobrahead streetlights were proactively converted. To date, 3,049 HID cobrahead streetlights have been proactively converted to LED. The Company completed the patrol and fix initiative, and advanced lighting controls initiatives in 2022 (discussed later in this direct testimony). Additionally, the Company is evaluating different contracting strategies to improve outage duration.

Q. Please describe the Company's 2024 streetlight outage restoration performance.

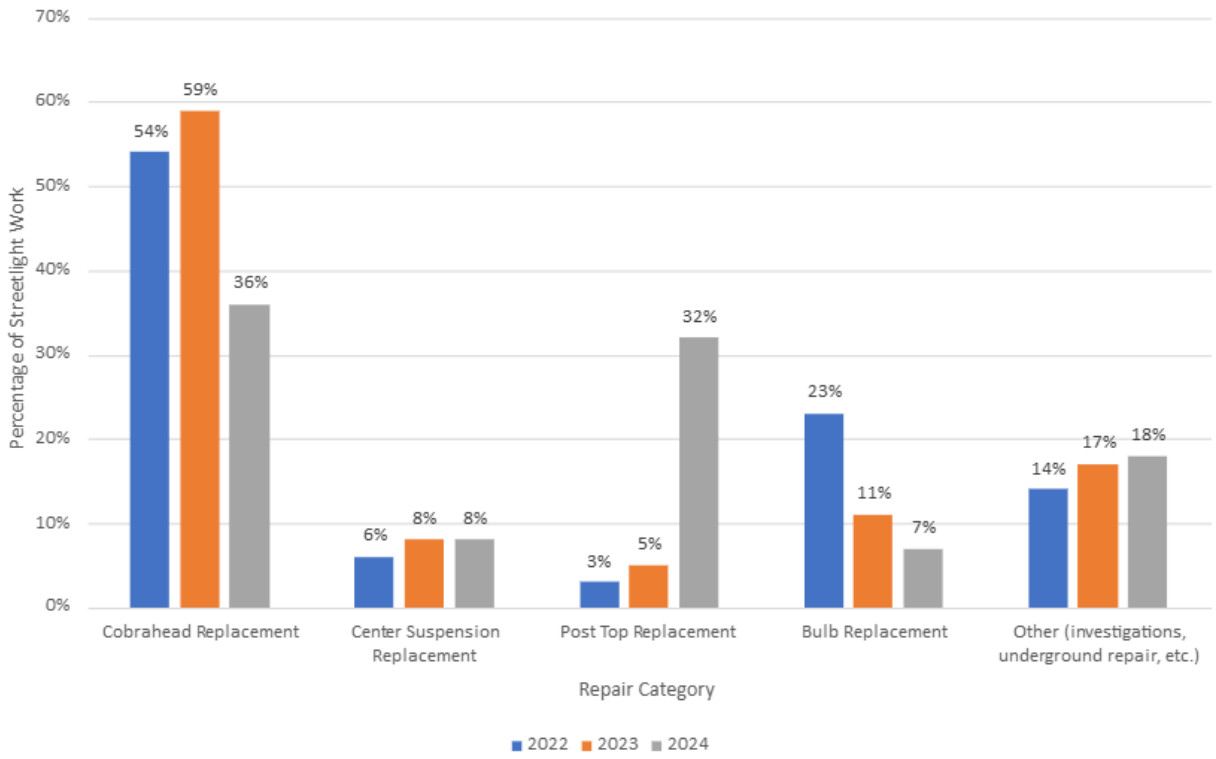
A. A total of 21,858 streetlight incidents were reported in 2024, 97% of which were reported via the SOAR application. Historical streetlight order creation by type is shown in Figure 2 below where the SOAR Application (Web Form) constitutes 21,101 of the incidents.

Figure 2
Streetlight Orders by Creation Type



These incidents between 2022 and 2024 resulted in the work as shown in Figure 3 below.

Figure 3
Work Type Breakdown of 2022 through 2024 Streetlight Orders



In 2024, the average streetlight outage duration was 14.65 days and the median outage duration was 7 days. In 2024, the average outage and median outage duration degraded compared to 2023 by 4.92 days and 2 days, respectively. Activities to improve streetlight outage performance are discussed later in this direct testimony.

Q. Does the Company prioritize other work ahead of streetlight outage restoration?

A. The Company prioritizes public safety related orders and emergent service restoration ahead of streetlight outage repairs. The workers who complete streetlight repairs are the same workers who perform emergent service restoration and respond to downed wire orders. While the Company has a financial incentive to prioritize streetlight repairs

because it is required to compensate streetlight customers with a streetlight outage credit pursuant to its tariff, it must prioritize restoration work in order of public impact.

Q. What does the Company believe are the causes or contributing factors of the increase in the number of streetlight orders from 2017 to 2024?

A. The Company believes the increased number of orders reflected in Figure 2 above reflects greater reporting of outages due to implementation of the SOAR application—not that the Company is necessarily experiencing more outages – because customers now have an easy-to-use self-service application for reporting streetlight outages. Additionally, the Company is no longer performing any lamp maintenance/replacement as it is converting HID cobrahead and post top fixtures upon failure. This practice is expected to result in a relatively uniform conversion of cobrahead and post top fixtures across nearly all municipalities and will ultimately lead to reduced streetlight orders due to the reduced maintenance required for LED streetlights.

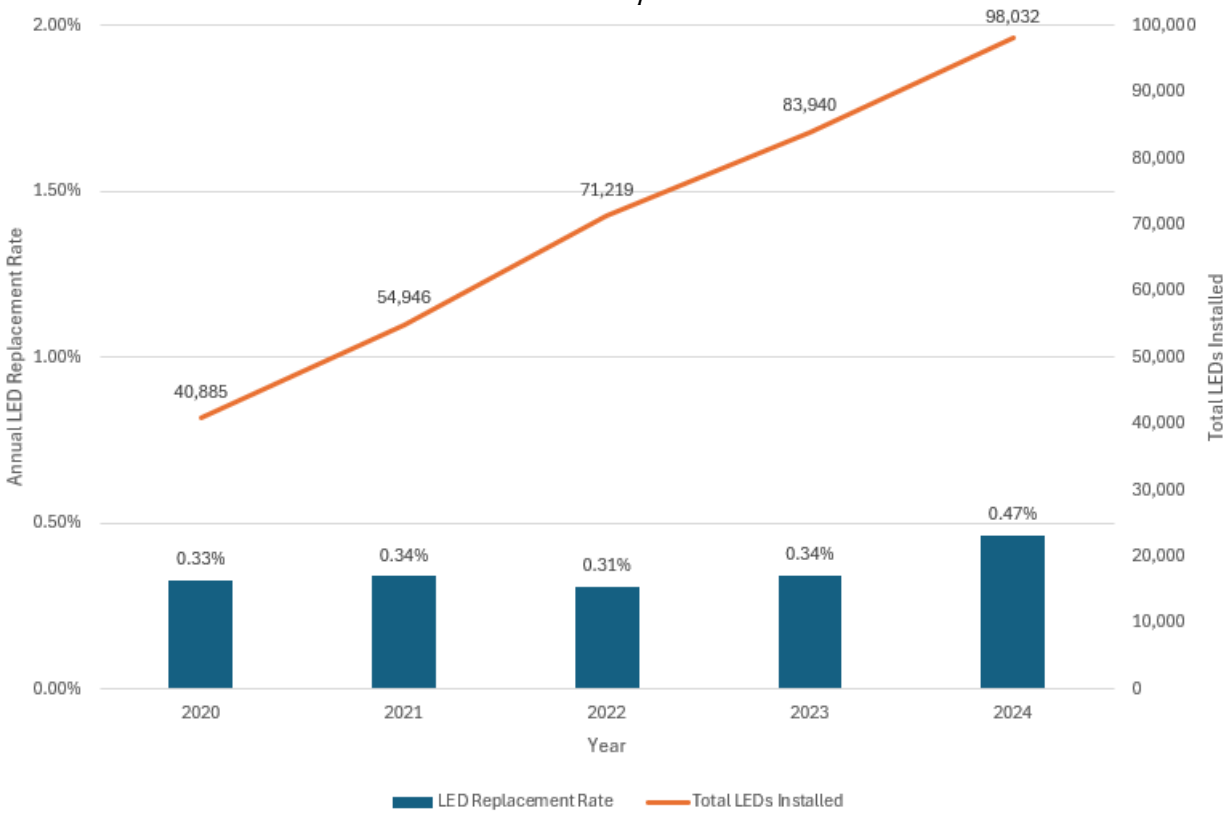
Q. What are the causes or contributing factors for the 27% increase in post top replacement orders in 2024?

A. The increase in post top replacement orders in 2024 is a result of LED conversion upon first failure mode of post top fixtures. Historically, if an HPS bulb was burnt out, the bulb would be replaced, not the entire fixture. This would result in a "Bulb Replacement" category order.

Q. What is the historical LED replacement rate?

A. Historical LED replacement data is shown below in Figure 4. LEDs are very reliable with a less than 0.5% replacement rate.

Figure 4
Historical LED Replacement Data



Q. Can the Company determine whether the LED luminaires it installs are defective without tracking outages by luminaire type?

A. Yes, the Company can determine whether LED luminaires are defective without tracking outages by luminaire type.

For product changes, the Company uses the First Part Approval process to validate the material changeover from HID to LED fixtures. This ensures the product meets standards and specifications.

For LED lighting defects (product non-conformances) identified by the field, the field team notifies the Supplier Quality Department; the Supplier Quality Department documents the quality issue and determines whether it is a non-conformance, the Company notifies the supplier of the defect, and the Company determines corrective actions. Street lighting non-conformances are documented in the Company's quality management software to record corrective and preventative actions required to prevent recurrence. Supplier Quality implemented tracking of product non-conformances in the Company's quality management software in 2022.

Q. Were there any streetlighting product non-conformances that required the removal and replacement of field installed equipment in 2024?

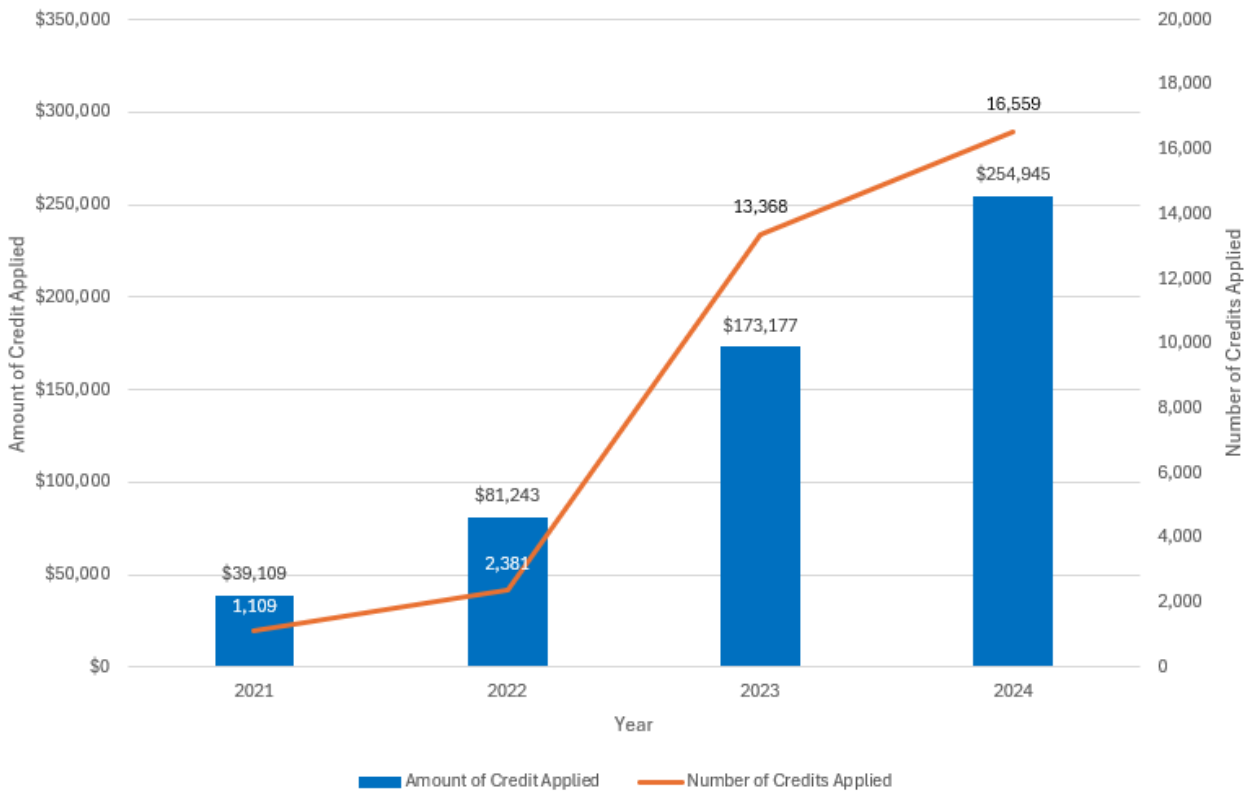
A. No. There were no streetlighting product non-conformances that resulted in the removal and replacement of field installed equipment in 2024.

Q. Does the Company provide credits to customers for streetlight outages?

A. Yes. Pursuant to the Company's current streetlight tariffs, the Company provides a pro-rated bill credit calculated from the date a streetlight outage is reported and continuing until the light is returned to service. The streetlight outage credit is issued within 90-days of the streetlight returning to service.

The Company provides an outage credit for each and every streetlight outage. However, the number of outage credits applied does not always equal the number of actual outages; outage credits by customer may reflect multiple outages for the same type of light. For example, if a customer has five 40-watt streetlight outages within a billing period, one credit would be applied for the total amount of the credits for all five lights. Historical streetlight outage credit data is shown in Figure 5 below.

Figure 5
Historical Streetlight Outage Credit Data



The increase in the number of outage credits applied between 2022 and 2024 is a direct result of the methodology for application of outage credits for all streetlight outages, regardless of duration (MPSC Case No. U-21203).

Q. Are there circumstances in which longer duration outages are unavoidable?

A. Yes. In certain circumstances, the ability to safely and timely restore a streetlight can be difficult. Streetlight knockdowns, underground cable faults, requirements for traffic control, and replacement of special-order materials can sometimes lead to longer duration streetlight outages.

Q. Does the Company monitor longer duration outages and their status?

A. Yes. All streetlight outages greater than 60 days are discussed in weekly workplan meetings. The Company's target is no more than 125 streetlight outages statewide exceeding 60 days in duration.

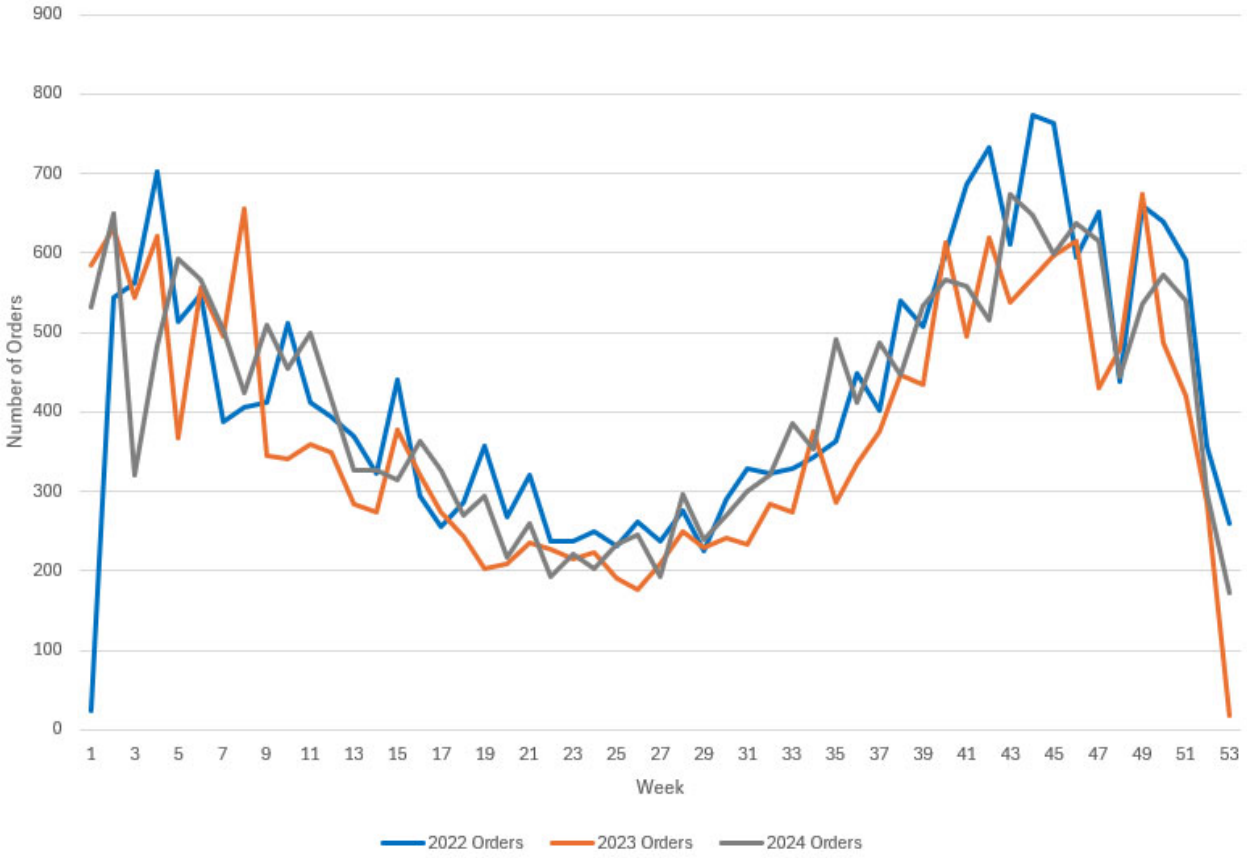
Q. Are longer duration outages localized, or do they occur through Consumers Energy's service territory?

A. Longer duration outages generally occur throughout Consumers Energy's service territory proportionate to the geographic dispersion of streetlights.

Q. Has the Company made any decisions regarding the future performance of streetlight outage restoration work?

A. Yes. Based upon variability of outages reported throughout 2022, 2023, and 2024, the Company has determined it will continue to employ a blend of Company resources and contractors to complete streetlight outage restoration work and vicinity upgrades. This resource strategy will allow the Company to flex its contracted resources to meet changing streetlight outage restoration demand. Figure 6 below represents differing levels of outages reported throughout the year, driving the need for a blended workforce.

Figure 6
Weekly Streetlight Order Count



Q. What other actions has the Company taken to improve streetlight outage restoration performance?

A. In addition to the implementation of cobrahead and post top vicinity upgrades, the Company completed a patrol and fix initiative (November 2021 through March 2022), completed an advanced lighting controls initiative in October 2022, solicited feedback from internal and external stakeholders regarding its SOAR application, completed one SOAR application upgrade, and is underway with the second SOAR application upgrade, completed evaluation of advanced lighting control implementation, and documented its long-term reliability plan in the Company's Reliability Roadmap. The Company has also implemented internal prioritization standards for restoration of outages greater than

60 days. With the exception of cobrahead and post top vicinity upgrades, the Company is not seeking to recover any investment in these initiatives.

Q. What were the results of the patrol and fix initiative?

A. The patrol and fix initiative was in place between November 2021 and April 2022 in the Adrian and Kalamazoo service territories, and in place mid-February 2022 through March 2022 in the Muskegon service territory. In total, nine cobrahead fixtures in Adrian, one cobrahead fixture in Kalamazoo, and six cobrahead fixtures in Muskegon were identified as failed and repaired upon identification.

Q. Does the Company intend on reinstating its patrol and fix initiative during the bridge period or test year?

A. Not at this time. From January 1, 2022 through March 31, 2022, 1,499 streetlight outages were reported by customers in the Adrian, Kalamazoo, and Muskegon service territories. Time spent searching for 16 outages that weren't reported is time that could have been spent repairing identified outages. The quantity of outages reported by customers is indicative of their adoption of the Company's reporting technology and its effectiveness relative to the patrol and fix initiative.

Q. What were the results of the advanced lighting controls initiative?

A. 204 total smart nodes were installed statewide (Flint, Jackson, Leelanau, Kalamazoo, Muskegon, and Marshall Training Center). The data collection period was October 1, 2022, through October 31, 2022. Ten smart nodes of each manufacturer were installed at each location (except Marshall Training Center). Evaluation criteria included: status of light visibility, identification of fault information, accurate metering of power usage, and energy savings provided for the customer.

Capabilities observed: manually turning streetlights on/off, manual dimming of streetlights, creation of scheduled dimming events, outage reporting of streetlights, and status communication of streetlights.

Q. Does the Company intend on reinstating the advanced lighting controls initiative in the bridge period or projected test year?

A. Not at this time. The Company completed an internal review of the initiative to determine the viability of technology implementation. The Company also surveyed participating municipalities in the first quarter of 2023 to collect feedback regarding features they like to use, software package preference, and overall customer sentiment for installation of advanced lighting controls. A formal business case will be prepared, and a summary of the results will be submitted for approval in a future electric rate case prior to any implementation. The 204 smart nodes remain in-service, and the Company continues to partner with the initiative participants to identify use cases and to define functional requirements for broader installation.

Advanced lighting controls provide features and functions that some municipalities may find beneficial, while some municipalities may find the expense outweighs these benefits. The Company will continue to gauge interest from its street lighting customers and evaluate project feasibility through established business planning processes.

Q. What were the results of the Company's internal review of the advanced lighting controls initiative?

A. Feedback from municipalities included not using all the product functionality, concern over internal cost to maintain, and concern over cost of implementation. Estimated O&M savings (reduced truck rolls) were less than anticipated costs associated with maintaining

the devices in the field and managing the digital experience (manage software program, integration with existing software (SAP, SOAR, etc.), coordination with manufacturer and municipalities, and maintenance of the new rate and tariff).

The Company has decided to pause implementation of advanced lighting controls based on the cost of the technology, lack of customer interest, and minimal O&M savings.

Q. Does the Company recommend other activities which are expected to improve outage restoration performance and/or reduce streetlight failures?

A. Yes. The Company's current practice of proactively converting HID cobrahead lights, via vicinity conversion, to LED luminaires has proven financially beneficial to street lighting customers. Approximately $291,000 in customer savings has been realized since 2022 through vicinity conversions by reducing non-premise time of field personnel. The Company will continue to perform cobrahead vicinity conversions as part of its expected work plan. As discussed further in this direct testimony, the Company recommends continuing HID to LED post top conversions upon failure and implementing vicinity conversion of HID post top lights. In 2024, 6,018 post top lights were converted to LED technology, extending the life of these assets.

Q. When did the Company begin converting HID post top streetlights to LED?

A. The Company began converting HID post top streetlights to LED in January 2024.

Q. Why does the Company convert HID post top streetlights to LED?

A. Post top streetlights represent the second largest quantity of HID streetlights the Company operates and maintains (approximately 43,000). Post top streetlights are typically unique, meaning other manufacturers do not produce the same exact streetlight. The Company's

HPS luminaire suppliers have indicated HPS post top streetlights have been discontinued mainly due to low demand amidst a higher demand for LED luminaires.

Implementing a post top reactive conversion program, similar to that already in place for cobrahead luminaires, would result in similar customer benefits (reduced energy use, no upfront cost, etc.,). This work plan is documented in the Company's Reliability Roadmap.

Q. Why does the Company recommend implementing vicinity conversions for HID post top streetlights?

A. Customer feedback received during HID cobrahead conversions indicate customers are sensitive to variation in lighting temperature (color). This sentiment is expected to be amplified in post top lighting applications, where lights are typically installed for beautification and the light temperature variation may not be aesthetically appealing. Vicinity conversion of HID post top lights reduces appearance of lighting temperature differences, leading to sustained or increased customer satisfaction, and improved reliability. Preliminary analysis of HID post top streetlight vicinity conversions indicates savings and improved reliability of service for street lighting customers.

Q. How did the Company evaluate vicinity conversions for HID post top streetlights?

A. The Company analyzed savings from 2022 when completing vicinity conversions on cobrahead streetlights. Vicinity conversions reduce the unit cost per conversion by reducing frequency of repair worker mobilization to the same area. Table 6 below illustrates the difference between a reactive conversion and a vicinity conversion.

The Company's latest version of the Reliability Roadmap (Exhibit A-129 (MPK-19)) reflects an assumption of 4,713 HID post top to LED conversions per year (800

vicinity conversions) starting in 2025. This equates to customer savings of $92,000 per year versus exclusively reactive conversion.

Q. What is SOAR and what is it intended to provide?

A. SOAR is a web-based application that allows customers to self-report streetlight outages. SOAR was implemented to increase customer satisfaction through self-service capabilities, reduce information technology related costs, reduce incoming call volume for contact centers, and improve the process for handling streetlight outages.

Q. When did the Company begin using the SOAR application.

A. The Company launched the SOAR application in 2021.

Q. Please describe the benefits of the SOAR application.

A. The SOAR application benefits customers in a variety of ways. Specifically, the SOAR application project deployed an accurate self-service streetlight outage notification program for use by customers, providing accurate streetlight outage identification and more rapid restoration resolution. Additionally, the project defined appropriate repair manifests and global positioning system ("GPS") locations to ensure deployed repair crews have the correct equipment and location. The project also provided customers with the capability to immediately identify the status of the repair online and avoid the need to contact Customer Service. Figure 7 below demonstrates streetlight information for a user-selected streetlight with the option to report an outage in SOAR. Figure 8 below shows in-service, in-progress, and extended repair streetlights on the SOAR map. Figure 9 below shows the status of the repair. Blue lights are operational, orange lights are reported as outages.

Figure 7
SOAR Screenshot: Streetlight Information

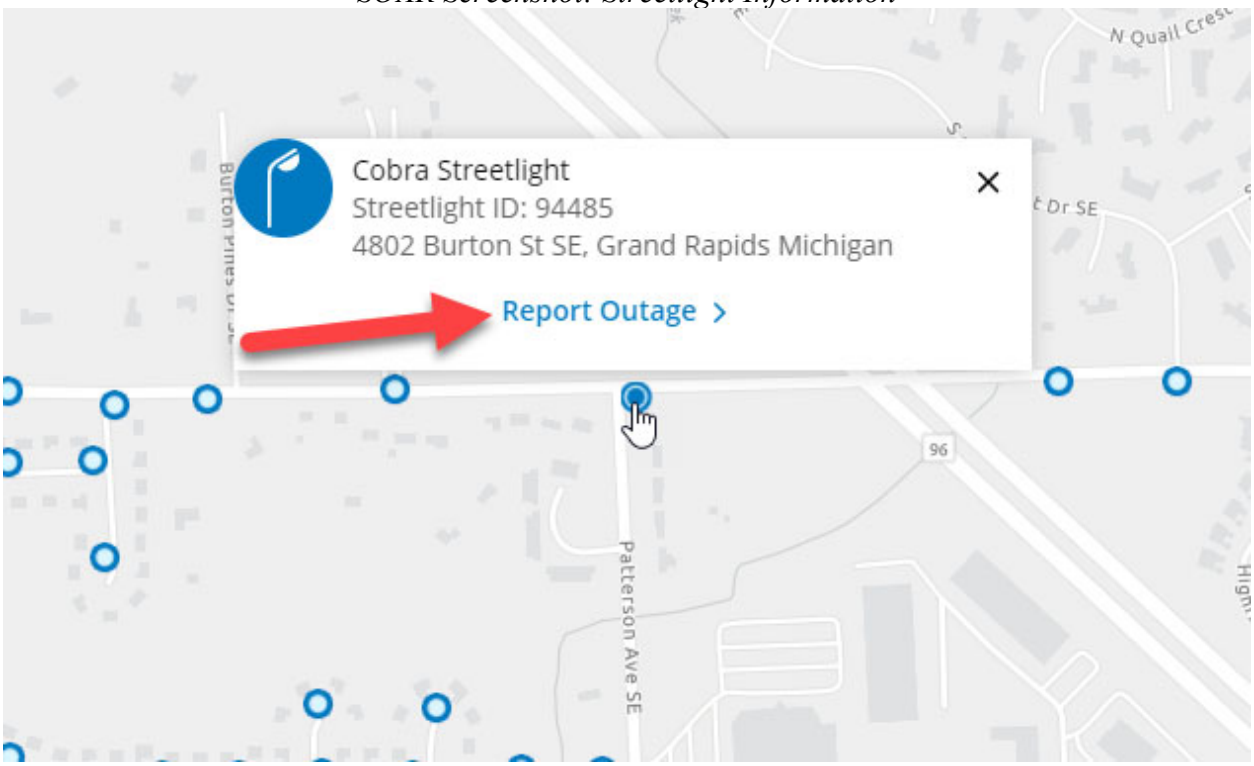


Figure 8
SOAR Screenshot: Streetlight Status on SOAR Map

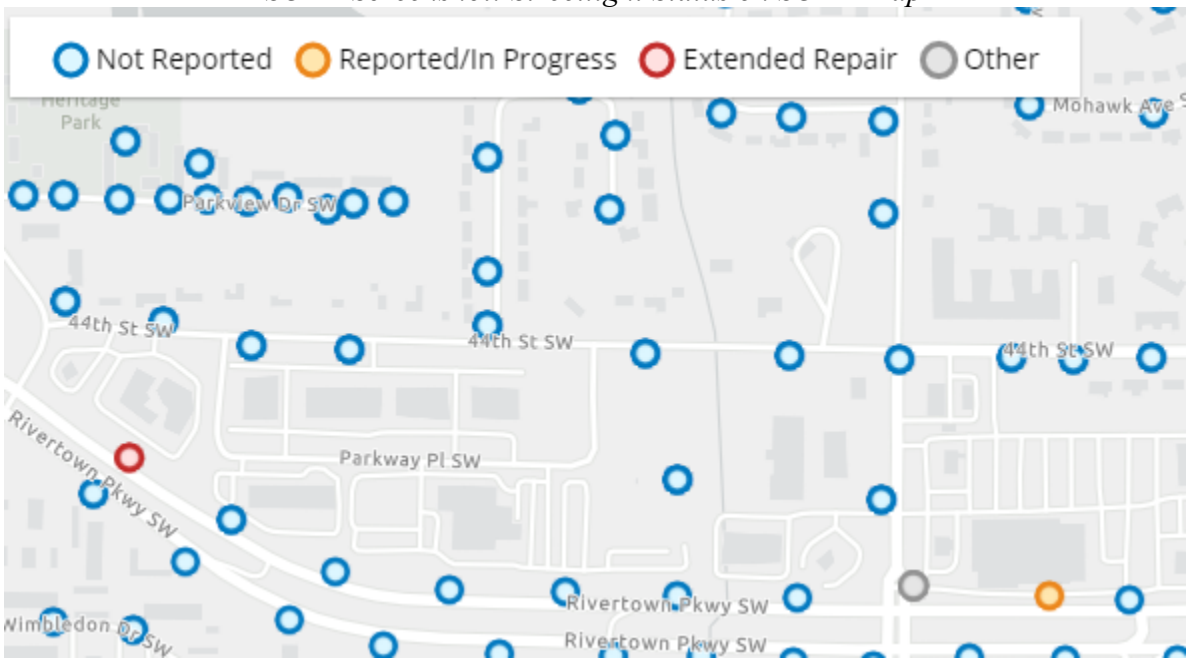
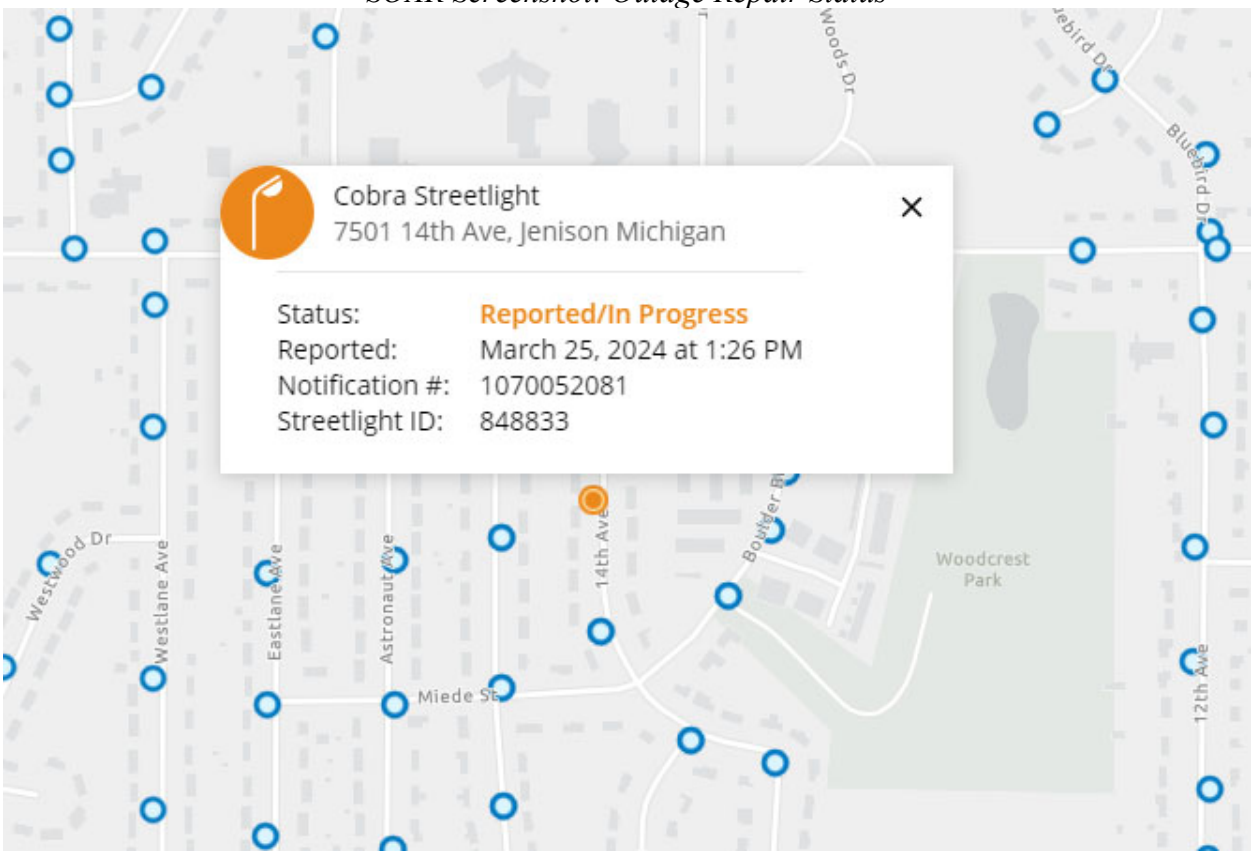


Figure 9
SOAR Screenshot: Outage Repair Status



Q. Does the SOAR application provide economic benefits in addition to the qualitative benefits previously described?

A. Yes. The SOAR application provides cost reductions in several ways. First, the SOAR application is projected to reduce customer calls, resulting in annual savings of $38,500 and resulting in improved customer satisfaction. Second, the SOAR application will eliminate duplicate reported outages, resulting in projected annual savings of $1.5 million due to the elimination of duplicate truck rolls (nearly 14% of the 20,419 streetlights reported in 2019 were duplicate orders). In addition to the projected cost reductions for the call center and field services, the SOAR application is projected to reduce annual Information Technology ("IT") support costs by $60,000 as a result of consolidating streetlight portal components into the core customer facing portal.

Q. Where are these economic benefits accounted?

A. The economic benefits have already been incorporated into the unit cost of the work the Company expects to conduct.

Q. Has the Company created a standard reliability report for streetlighting performance?

A. Pursuant to Case No. U-21389, the Company, MI-MAUI, and MPSC staff worked together to identify metrics to include in reliability reporting. The Company presented its plan to MPSC staff regarding including self-service reliability reporting from the SOAR application on June 5, 2024. The self-service reporting was included in Case No. U-21585.

Q. Do you have any final thoughts regarding the Company's outage identification and restoration process?

A. Yes. As I have already discussed, the Company has evaluated and continues to evaluate a number of different customer streetlighting service concerns, and will use continuous improvement methods to identify and implement process improvements where applicable. The Company has completed its patrol and fix, and advanced lighting control initiatives. The Company is now converting HID post top and cobrahead fixtures to LED technology upon failure. Streetlighting reliability is further advanced through the execution of vicinity conversions for both cobrahead and post top luminaires. Additionally, the Company has augmented its own field resources with contracted resources, and is continuing to engage customers regarding advanced lighting control installations. The Company will continue to collaborate with its streetlight customers, MI-MAUI, and other interested stakeholders in the future, as demonstrated by its participation in the working group resulting from

DTE's order in Case No.: U-21534 to continue to improve the streetlighting service that it provides to its customers.

IV. LED STREETLIGHT EQUIVALENCY EVALUATIONS AND NEW BUSINESS

Q. Please describe the Company's process to evaluate the equivalency of replacement LED lighting.

A. The Company relies on technical standards to help ensure the proper amount of illumination is provided to roadways. The Company's primary focus in selecting replacement LED lighting is the actual equivalency of the selected alternative to ensure roadways are properly illuminated for safety while controlling costs. There are multiple technical factors the Company evaluates to ensure equivalency, such as total light loss factor, which includes lamp lumen depreciation and dirt depreciation, and roadway and pedestrian activity classifications. Considerations such as the specific location of the existing lighting relative to the roadway it is intended to illuminate are also important. I will discuss additional standards the Company considers in its equivalency evaluations later in this testimony.

Q. What is the origin of the Company's equivalency standards?

A. In 2014 and 2015, the Company worked closely with a lighting consultant to not only develop its LED specification, but also developed a method by which the Company could verify the LEDs submitted for consideration are equivalent to the luminaires they are intended to replace. The method the Company uses ensures the selected LED luminaire will adequately provide equivalent roadway illumination.

Q. Please specify what roadway lighting standard(s), if any, the Company follows?

A. The Company uses ANSI/IUES RP-8-22 Recommended Practice for Lighting Roadway and Parking Facilities.

Q. Please explain what luminaire performance factors the Company evaluates for equivalency. Please address specifically, but not exclusively, lumens, light distribution patterns, Backlight-Uplight-Glare ratings, Correlated Color Temperature, and Color Rendering Index.

A. For equivalency, the Company uses Agi32 software to verify optimized span lengths based on roadway classification and pedestrian activity to determine equivalency compared to the span lengths of existing HPS cobrahead fixtures. The performance factors listed in the question are used to determine conformance to the Company's specifications but not equivalency.

Q. How often does the Company competitively evaluate replacement lighting?

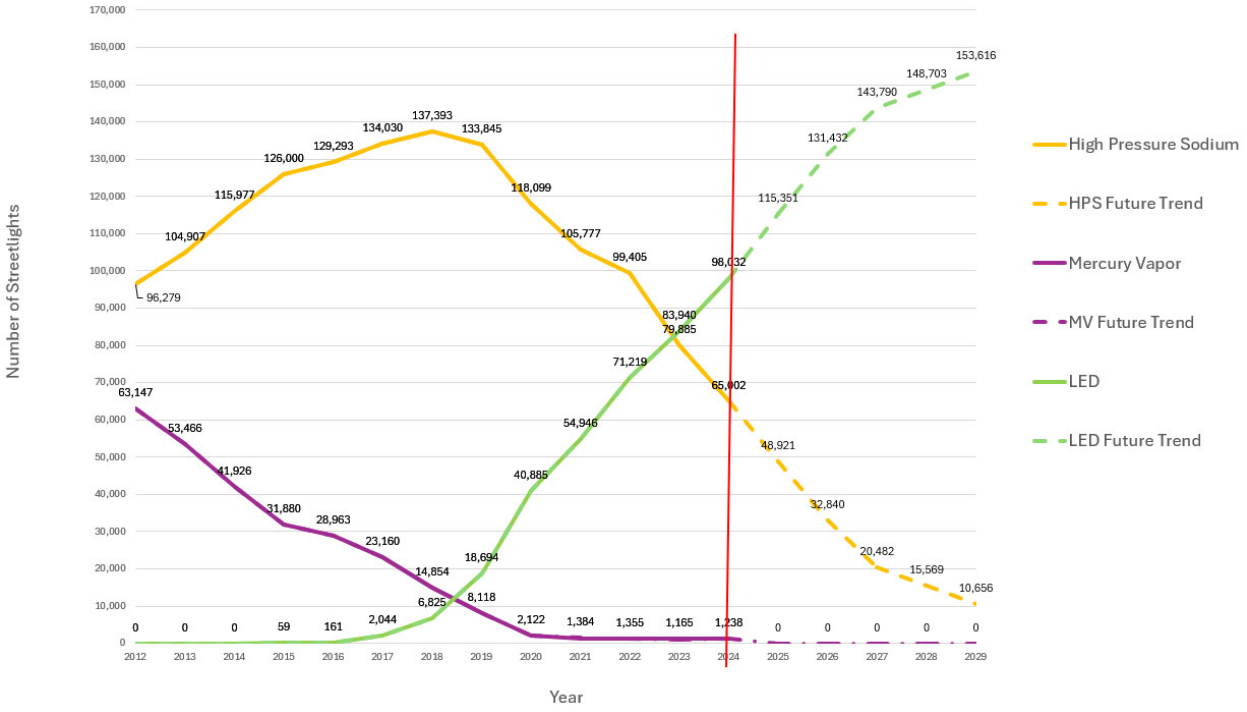
A. The Company typically issues competitive solicitations every three years, with the Company's most recent competitive solicitation completed in January 2025. As part of the most recent solicitation, the Company evaluated the latest equivalent LEDs submitted by multiple manufacturers. Streetlight technology, like many other technologies, changes and improves frequently. However, it would be unreasonable to evaluate the changing technology more frequently than every three years.

Q. How have technology trends impacted installations?

A. See Figure 10 below for historical and projected lighting technology installed. LED and HPS Future Trends in Figure 10 (below) reflect post top LED conversions (reactive and

vicinity), as outlined in the Reliability Roadmap (Exhibit A-129 (MPK-19), pages 127 through 132).

Figure 10
Streetlight Technology Trend



Q. For each HID cobrahead, post-top, or center suspension wattage and type (HPS, MV, MH) of which the Company had more than 3,000 deployed at the end of 2023, please provide the standard (or most common) LED equivalent wattage used before and after the 2025 competitive solicitation.

A. Pre- and post-2025 competitive solicitation LED equivalent wattages are shown in Table 1 below.

Table 1
LED Equivalent Wattages

Fixture Type	LED Wattage Prior to 2025 Bid	LED Wattage post 2025 Bid
Cobra	40W	30W
Cobra	70W	60W
Cobra	80W	70W
Cobra	150W	140W
Center Suspension	40W	40W
Center Suspension	70W	70W
Traditional Non-Cutoff Post Top	50W	50W

Q. Why doesn't the Company competitively solicit replacement lighting more frequently?

A. The effort to replace its existing LED lighting portfolio is not a small undertaking. Considerations such as depletion of existing inventory, satisfaction of existing lighting contracts, and complete evaluation of alternative lighting products is a considerable effort. The establishment of lighting contracts that have a minimum term of three years results in better unit pricing from manufacturers in comparison to contracts for only one or two years, which would have smaller contract values. It would be unreasonably expensive to engage in a competitive solicitation process annually. This would effectively result in the need for additional resources, both engineering and supply chain, with little or no economic benefit. Although manufacturers continuously improve their lighting products, the Company must make strategic decisions as to how frequently it can transition from its current lighting products to new lighting products.

Q. How does the Company evaluate alternative LED lighting products to ensure equivalency?

A. The Company begins its evaluation of alternative LED lighting products by ensuring the wattage of the replacement LED luminaire is equal to or less than the wattage of the

luminaire it will replace, to ensure the replacement product's monthly rate is the same or less expensive than the existing luminaire, all else being equal. The next step in the equivalency process is to consider the specific roadway application, including roadway classification, pedestrian activity, pavement class, roadway width, location, and mounting height to ensure the average luminance, average and maximum uniformity, and the maximum veiling luminance (disability glare) is in accordance with industry guidelines. The next consideration for the evaluation is to perform a financial analysis among replacement equivalent products for impacts to the customer as well as the Company. The final consideration for the evaluation of equivalent lighting products is the aesthetics of the replacement luminaire.

Q. Does the Company's equivalency evaluation process ensure that replacement LED lighting meets DesignLights Consortium ("DLC") Qualified Products List criteria?

A. Yes. This criteria was included in the Company's most recent competitive solicitation for LED lighting products. In addition, all LED cobrahead luminaires previously selected in the Company's competitive solicitations since 2018 also met this criteria.

Q. Please explain why DLC certification is important.

A. DLC is a group that certifies light output used in energy rebates around the world. This group independently certifies the quality and performance of lights. DLC essentially ensures luminaires meet their advertised specifications for lumen output, color rendering index, color temperature, total harmonic distortion, power factor, etc. Selection of a DLC-certified light helps ensure you receive a quality product.

Q. Does the Company only utilize the equivalency evaluation process to support lighting conversions?

A. No. The Company also leverages the technical characteristics of the newly selected lighting to support lighting designs for new streetlight installations. The Company receives customer requests for installation of new streetlighting (i.e., new subdivisions) and leverages the results of the LED lighting evaluations to design the new lighting.

The capital expenditures associated with new streetlighting are reflected in Exhibit A-12 (DAS-1), Schedule B-5.9, page 1, line 1.

Q. Does the Company utilize the LED fixtures for purposes other than existing light conversion?

A. Yes. The Company uses the LED cobrahead and post top fixtures in new business applications as well. Projected new business expenditures are summarized in Table 2 below.

Table 2
Projected New Business Expenditures

Period / Year	Amount	Units
Bridge Period (ending 4/30/2026)	$4.869 million	294
Test Year (ending 4/30/2027)	$3.727 million	220

Q. How did the Company develop the projected capital expenditures for streetlighting new business?

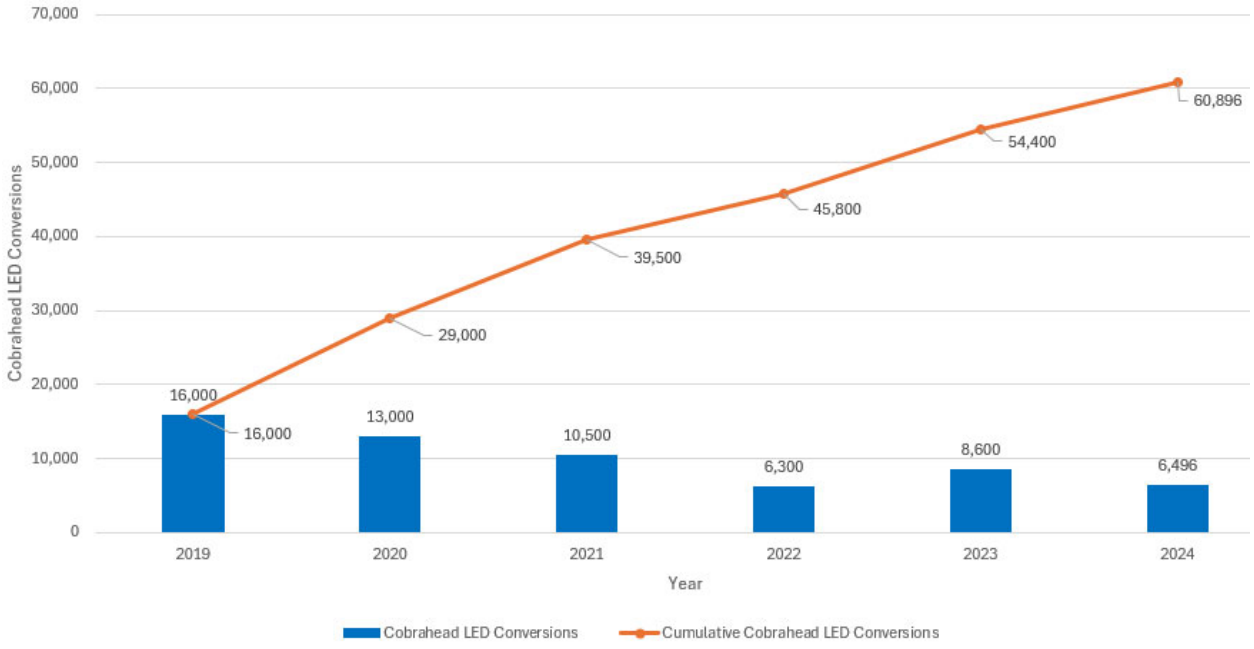
A. The Company calculated the five-year historical average capital expenditure amount for the period from 2020 through 2024 and escalated that amount by an inflation rate of 2.1% for 2025, 2.4% for 2026, and 0.8% for 2027. The number of new business streetlights and their unit costs are presented in Exhibit A-12 (DAS-1), Schedule B-5.9, page 2, lines 1 and 2.

V. CONVERSION OF COBRAHEAD, POST TOP, AND CENTER SUSPENSION STREETLIGHTS

Q. Please describe the Company's project to convert cobrahead streetlights from HID to LED.

A. Beginning in fall 2018, the Company made the decision to reactively convert all failed cobrahead streetlights from HID to LED as previously discussed in my testimony. Figure 11 below shows annual cobrahead LED conversions.

Figure 11
Annual Cobrahead LED Conversions



These reactive conversions are in addition to the MV conversions discussed later in this testimony. The Company expects that it will convert the remaining HID cobrahead fixtures over the next two to three years.

Q. Why would the Company expect that all of its HID cobrahead fixtures would fail over the next two to three years?

A. The lamps on the HID fixtures are rated for 24,000 hours of service. With approximately 4,200 hours of lighting service annually, the average life of the lamps is approximately six years.

Because the Company discontinued the repair and began to convert all failed cobrahead HID fixtures to LED technology in 2018, it is reasonable to expect all remaining HID fixtures would fail in the next two to three years.

Q. How is the projected streetlighting expenditure level aligned with the Reliability Roadmap?

A. As described in the Reliability Roadmap (Exhibit A-129 (MPK-19)), these expenditures are essential to extend the lifecycle of luminaires and reduce repair expenses across the Company's streetlight portfolio. Conversion of post top luminaires to LED technology increases their lifecycle, thereby reducing future outages. Vicinity conversions of cobrahead and post top luminaries prior to failure increases the efficiency of field personnel to reduce to the cost of conversions and, effectively eliminates near-term outages.

Q. Is the Company proposing a change to the cobrahead vicinity conversion program?

A. Yes. The Company will continue to convert HID cobrahead fixtures in the vicinity of failed cobrahead fixtures. The Company will target 260 cobrahead vicinity conversions per year, recognizing outage restoration is of higher priority than a conversion of a luminaire that has not failed. Average outage restoration has degraded 4.92 days since 2023. Reducing the Company's vicinity conversion target will provide additional flexibility to address failures in a timelier manner while providing customers the benefit of a reduced conversion

cost and avoided future outages. Improved focus on demand failure restoration, resulting in a reduced average outage duration, is the primary driver of reducing the vicinity conversion plan.

The Company has performed an evaluation of three cobrahead conversion options: reactive, planned, and lights in the vicinity. A summary of the projected unit costs associated with each option is shown in Table 3 below.

Table 3
Cobrahead Conversion Projected Unit Costs

Reactive Conversion	Planned Conversion	Vicinity Conversion
$732.00	$684.06	$616.94

The reactive conversions have the highest unit cost but are a necessity as the light has already failed and requires attention. The incremental cost to convert the failed light to LED is essentially the cost of a vicinity conversion as travel time to the light cannot be avoided.

Q. Are all of the currently installed LED fixtures a result of the Company's reactive conversion program?

A. No. The Company effectively completed its planned MV conversion program in 2020. In the last decade, the Company has reduced its quantity of MV luminaires from more than 63,000 luminaires to approximately 1,200 luminaires, all of which are center suspension streetlights that I will discuss later in this testimony. At the beginning of the MV conversion program, the MV luminaires were converted to HPS, however in recent years the MV luminaires have been converted to LED. The Company also installed customer requested new LED lights as well as any customer requested conversion of existing HID

fixtures to LED. Figure 10 above represents the Company's historical progress and illustrative continued progress.

Q. What are the projected investments for all streetlight failures?

A. Projected streetlight failure expenditures are summarized in Table 4 below.

Table 4
Projected Streetlight Failure Expenditures

Period / Year	Amount	Units
Bridge Period (ending 4/30/2026)	$20.229 million	20,028
Test Year (ending 4/30/2027)	$11.800 million	13,800

These projected quantities include all fixture types including cobrahead, center suspension, post top, and floodlights.

Q. How did the Company develop the projected capital expenditures for streetlighting demand failures?

A. The projected number of demand failures was based upon the number of capital streetlight demand failures for the period from 2019 through 2023. This figure was increased to include post top LED conversions as described in the Company's Reliability Roadmap (Exhibit A-129 (MPK-19). These figures were then multiplied by a projected unit cost for reactive conversion. The number of demand failure streetlights and their unit costs are presented on Exhibit A-12 (DAS-1), Schedule B-5.9, page 2, lines 9 and 10.

Q. Can you explain what you mean by planned and reactive conversions?

A. Yes. Planned conversions are performed on HID lighting that have not yet failed. The Company's reactive program, in contrast, will perform its HID to LED conversions on cobrahead fixtures, post top fixtures, and center suspension fixtures that have failed in service. The Company's standard practice since 2018 had been to only convert cobrahead fixtures upon failure; however, the Company extended that practice to center suspension

fixtures beginning in 2022, and post top fixtures in 2024. The preferred method for conversion of center suspension failures will be through the use of a direct replacement LED at failure, as discussed later in this testimony.

In addition, as previously discussed, the Company began to convert HID cobrahead fixtures in the vicinity of failed cobrahead fixtures in April 2022, and HID post top fixtures in the vicinity of failed post top fixtures in February 2025.

Q. Why did the Company originally choose to convert its cobrahead streetlights from HID to LED on a reactive basis versus a planned basis?

A. There were significant benefits to offering a reactive LED conversion program to address the concerns the Company has heard from a number of its streetlighting customers. The feedback the Company received from its customers was that they wanted to move to LED lighting versus the existing HID technology as quickly as possible. The Company also received feedback that many of its customers did not want to pay total project cost for the planned conversions or for conversions at all. Many municipal customers operate under very tight budget constraints and may not have the available resources to execute on a community-wide planned replacement of all their streetlights, which would require a significant up-front customer contribution. Replacing lights on a reactive basis means that customers do not require any up-front contribution.

Q. What were some of the other considerations with a reactive conversion approach?

A. With a service territory of approximately 28,000 square miles, and more than 800 streetlighting customers, a planned approach to converting streetlights would unnecessarily advantage certain customers over others. In addition, and as previously discussed, the rated life of the HID lamp is 24,000 hours and, as a result, the Company knew it would visit the

majority of HID cobrahead streetlights over seven years for lamp replacement and/or complete luminaire replacement. Since the Company already had to visit the light due to its operational status, it made sense to simply convert the light upon failure rather than make a separate trip to the light to convert on a planned basis. As a result, the Company made a decision to embark on a program to replace all HID cobrahead luminaires upon failure. This balanced approach was deemed to be fair and equitable because it provides each community with the benefit of LED lights at approximately the same conversion rate, absent an up-front cost to the customer. Therefore, the benefits and costs of the investment into streetlights is equally realized by all customers with this approach. In contrast, a Company-planned conversion with no up-front contribution would mean some communities are paying for others to realize the benefit of LED lighting while receiving no benefit themselves.

Q. Can you summarize the Company's selection of its reactive approach to cobrahead LED conversions?

A. Yes. Based upon the various factors that I have just discussed, including the cost comparison and the fact that the Company would already need to visit the majority of its HID cobrahead lights over five to six years since the inception of the program in 2018, the Company felt that its reactive conversion methodology upon failure provided a balanced approach to moving to LED streetlighting for all customers with no up-front contribution from customers. The Company's decision to also convert HID cobrahead lights in the vicinity of failed cobrahead streetlights is consistent with the intent of its original reactive conversion program and continues to be fair and balanced, will reduce the average cost per conversion, and will expedite the conversion process.

Q. Has the Company previously evaluated other cobrahead streetlight conversion models?

A. Yes. In addition to the replacement of cobrahead streetlights upon failure and the replacement of cobrahead streetlights in the vicinity of failed cobrahead streetlights, the Company also considered the conversion of cobrahead streetlights on a planned basis. Although the Company made the decision to go with its approach of replacing cobrahead streetlights upon failure as its preferred approach, customers who want to convert their cobrahead streetlights in a planned fashion still have that option as long as they pay for the upfront conversion costs.

Q. What is the Company's priority with respect to reactive cobrahead streetlight conversions?

A. As discussed earlier in this testimony, the Company's focus is to address failed luminaires to restore lighting to its customers as quickly as possible, which customers have indicated they want and deserve, versus focusing resources on planned lighting conversions. The additional conversion of cobrahead fixtures in the vicinity of failed cobrahead fixtures will expedite the overall conversion process at a reduced cost, and will eliminate near-term outage events for these lights.

Q. Why does the Company convert post top streetlights from HID to LED?

A. Post top luminaire vendors began to phase out production of HID luminaires and components in 2021. By the end of 2023 all the Company's lighting vendors had completely discontinued HID post top product offerings. Because post top HPS product offerings are no longer an implementable solution, conversion to LED technology will

extend the lifecycle of the luminaire, and reduce the frequency of post top luminaire outages.

Q. Why has the Company chosen to convert its post top streetlights from HID to LED on a reactive basis versus a planned basis?

A. The reasons for choosing to reactively convert post top streetlights are similar to those that I previously discussed regarding reactive conversion of cobrahead streetlights. Replacing lights on a reactive basis is in line with customer feedback, and does not require any up-front contribution from customers.

Q. Why did the Company not move forward with conversion of its post top streetlights from HID to LED when it began reactive conversion of cobrahead streetlights to LED?

A. The Company did not move forward with the reactive conversion of post top streetlights at the same time as cobrahead streetlights because the Company recognized customers select post top streetlights based on aesthetics and style, unique to their application and location, and the Company wanted to evaluate and provide customers with the best LED post top lighting options. After careful consideration of the LED options and an understanding of what customers want, the Company chose two color options, amber (3000 Kelvin Temperature) and white (4000 Kelvin Temperature) for newly installed lighting requests and replacements of discontinued HID post top lighting. Lastly, cobrahead streetlights were the Company's largest lighting class, and are primarily supplied via overhead conductor. Post top streetlights represented a smaller percentage of the Company's streetlights and are supplied via underground conductor. Customer sentiment was favorable toward reactive conversion of cobrahead streetlights.

Q. What were some of the Company's other considerations with a reactive conversion approach for post top conversions?

A. The other considerations with a reactive conversion approach for post top conversions are similar to those I previously discussed regarding cobrahead conversions. A planned approach to converting streetlights would unnecessarily advantage certain customers over others. This balanced approach is fair and equitable because it provides each community with the benefit of LED lights at approximately the same conversion rate, absent an up-front cost. Therefore, the benefits and costs of the investment into streetlights is realized by all customers with this approach.

Q. Can you summarize the Company's selection of its reactive approach to post top LED conversions?

A. Yes. The Company's selection of its reactive approach to post top LED conversions is similar to its selection of its reactive approach to cobrahead LED conversions, which I have previously discussed. The Company has deemed that its reactive conversion methodology upon failure a balanced approach to moving to LED streetlighting for all customers with no up-front contribution from customers.

Q. Has the Company previously evaluated other post top streetlight conversion models?

A. Yes. In addition to the replacement of post top streetlights upon failure the Company also considered the conversion of post top streetlights on a planned basis. Although the Company made the decision to go with its approach of replacing post top streetlights upon failure as its preferred approach, customers who want to convert their post top streetlights in a planned fashion still have that option as long as they pay for the upfront conversion costs.

Q. What is the Company's priority with respect to reactive post top streetlight conversions?

A. As discussed earlier in this testimony, the Company's focus is to address failed luminaires to restore lighting to its customers as quickly as possible, which customers have indicated they want and deserve, versus focusing resources on planned lighting conversions. Additional conversion of post top streetlight fixtures in the vicinity of failed post top fixtures will expedite the overall conversion process at a reduced cost and will eliminate near-term outage events for these lights.

Q. How is the Company addressing the failure of HID center suspension streetlights?

A. The Company has identified, evaluated, tested, and contracted for a direct replacement LED center suspension fixture that will accommodate most center suspension streetlight locations. The Company will use the direct replacement LED center suspension fixture as its preferred replacement for center suspension streetlights. The Company expects it will convert the approximate 11,000 HID center suspension fixtures to LED over the next two to three years through its reactive replacement plan. Similar to the HID cobrahead fixtures, the HID lamps are rated for 24,000 hours of service and, as a result, should experience failure in five to six years based upon 4,200 hours of lighting service annually.

Q. What is the Company's strategy regarding use of direct replacement of center suspension streetlight fixtures?

A. Since 2022, the Company's preferred option has been the use of direct replacement center suspension streetlight fixtures because it is more economical and requires less intensive construction methods to install. Situations may exist that require the relocation of center

suspension fixtures to the side of the road, however the Company will always attempt to use direct replacement center suspension fixtures upon failure.

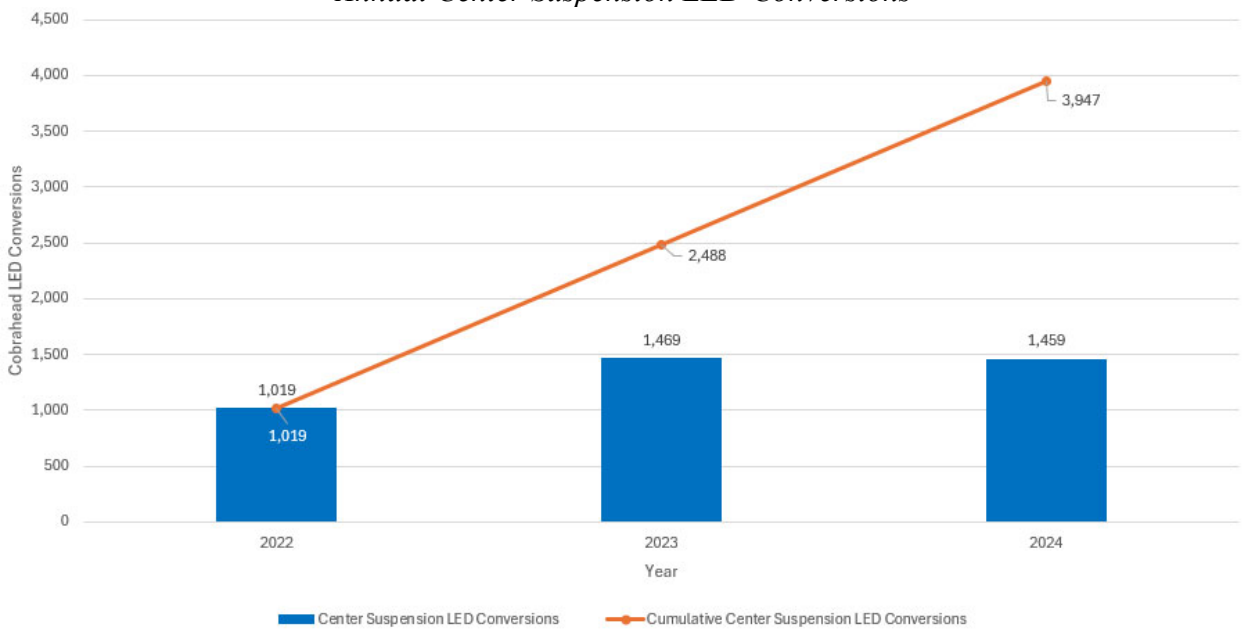
Q. What is the expected failure rate of the center suspension streetlights?

A. The Company expects center suspension streetlight failures to match the failure rate of cobrahead luminaires. With a total population of 11,000 center suspension installations across the state and an assumed 15% annual failure rate, the frequency of work in dangerous roadway situations is estimated at 1,650 lights annually.

Q. How many HID to LED center suspension conversions have occurred on an annual basis?

A. Figure 12 below shows annual HID to LED center suspension conversions.

Figure 12
Annual Center Suspension LED Conversions



VI. PLANNED STREETLIGHT CONVERSIONS

Q. Please describe the Company's planned conversions of cobrahead streetlights.

A. The Company will continue planned conversion of cobrahead streetlights located in the vicinity of failed cobrahead streetlights in 2025. The Company initiated planned

conversions of cobrahead streetlights in April 2022. The planned conversion of cobrahead streetlights will leverage the fact that the crews have already traveled to the location of a failed cobrahead streetlight and, as a result, this will reduce truck rolls and indirect costs in the replacement of the additional cobrahead fixtures in the vicinity of the failed fixture.

Q. What is the expected reduction in truck rolls resulting from the conversion of lights in the vicinity of failed cobrahead streetlights?

A. As I will discuss later in this direct testimony, the Company is projecting it will convert 347 cobrahead streetlights in the 16-month projected bridge period ending April 30, 2026, and 260 cobrahead streetlights in the projected test year ending April 30, 2027, which are located in the vicinity of failed cobrahead streetlights. Table 5 below summarizes vicinity conversion per year, by type. Because all of the cobrahead streetlight fixtures are expected to fail in the next two to three years due to lamp life, the Company will avoid a future truck roll for each cobrahead streetlight in the vicinity of a failed cobrahead streetlight. 347 truck rolls are expected to be reduced in the 16-month bridge period ending April 30, 2026, and 260 truck rolls are expected to be reduced in the projected test year ending April 30, 2027.

Q. How did the Company determine the projected number of cobrahead streetlights in the vicinity of failed cobrahead streetlights?

A. The Company used five years of historical failure data to project the number of failed cobrahead fixtures. To accelerate the improvement in streetlight reliability, in alignment with the Company's Reliability Roadmap filing, the Company increased its vicinity conversion ratio to one vicinity conversion to one failed cobrahead.

Q. Please describe the Company's planned conversions of post top streetlights.

A. Based on increasing HID post top product obsolescence, the Company began to reactively convert post top streetlights in 2024 and execute planned conversions of post top streetlights in the vicinity of failed post top streetlights in 2025. The planned conversion of post top streetlights leverages the fact that crews have already traveled to the location of a failed post top streetlight and, as a result, this will reduce truck rolls and indirect costs in conducting the replacement of the post top fixtures in the vicinity of a failed fixture. This workplan is described in Exhibit A-129 (MPK-19), the Company's latest version of the Reliability Roadmap.

Q. Has the Company changed the post top vicinity conversion program since the 2023 Reliability Roadmap filing?

A. Yes. The Company will target 800 post top vicinity conversions per year, recognizing outage restoration is of higher priority than a conversion of a luminaire that has not failed. Average outage restoration has degraded 4.92 days since 2023. Reducing the Company's vicinity conversion target will provide additional flexibility to address failures in a timelier manner while providing customers the benefit of a reduced conversion cost and avoided future outages. Improved focus on demand failure restoration, resulting in a reduced average outage duration, is the primary driver of reducing the vicinity conversion plan.

Q. What is the expected reduction in truck rolls resulting from the conversion of lights in the vicinity of failed post top streetlights?

A. As I will discuss later in this direct testimony, the Company is projecting it will convert 1,067 post top streetlights in the 16-month projected bridge period ending April 30, 2026, and 800 post top streetlights in the projected test year ending April 30, 2027, which are

located in the vicinity of failed post top streetlights. Table 5 below summarizes vicinity conversion per year, by type. Because all of the post top streetlight fixtures are expected to fail within approximately seven years of the start of the program due to lamp life, the Company will avoid a future truck roll for each post top streetlight in the vicinity of a failed post top streetlight. 1,067 truck rolls are expected to be reduced in the 16-month bridge period ending April 30, 2026, and 800 truck rolls are expected to be reduced in the projected test year ending April 30, 2027.

Q. How did the Company determine the projected number of post top streetlights in the vicinity of failed post top streetlights?

A. The Company assumed that all post top lamps would fail within seven years, equating to approximately 3,900 post top failures per year. Aligning with the cobrahead vicinity conversion tactic, the Company established a baseline that provides for conversion savings and future outage avoidance benefit for the customer.

Q. How did the Company develop the projected capital expenditures for vicinity conversions?

A. Based upon the projected material and labor costs, including loadings, the Company developed a projected cost per vicinity conversion of $616.94 for cobrahead lights and $1050.94 for post top lights. This unit price essentially eliminates the cost of a truck roll and travel time as compared to the unit cost for a reactive cobrahead conversion. Projected vicinity conversions by type are shown in Table 5 below. A summary of the projected unit costs associated with post top conversions is shown in Table 6 below. Projected vicinity conversion expenditures are summarized in Table 7 below.

Table 5
Projected Vicinity Conversions by Type

Year	Cobrahead Vicinity Conversions	Post Top Vicinity Conversions
2025	260	800
2026	260	800
2027	260	800

Table 6
Post Top Conversion Projected Unit Costs

Reactive Conversion	Planned Conversion	Vicinity Conversion
$1,166.00	$1,118.06	$1,050.94

Table 7
Projected Vicinity Conversion Expenditures

Period / Year	Amount	Units
Bridge Period (ending 4/30/2026)	$1.334 million	1,413
Test Year (ending 4/30/2027)	$1.018 million	1,040

Q. What level of spending was included for rate recovery by the Commission in Case No. U-21585 for the 14-month bridge period ending February 28, 2025 and test year ending February 28, 2026?

A. The Commission approved $24.695 million for recovery in current rates for the 14-month bridge period, and $24.812 million for recovery in current rates for the test year.

Q. What cost is the Company projecting for streetlighting capital investments in this case for the 16-month bridge period ending April 30, 2026 and test year ending April 30, 2027?

A. The Company is projecting $26.432 million of streetlighting capital expenditures for the 16-month bridge period, and $16.545 million of streetlighting capital expenditures for the test year.

Q. Please summarize the customer benefits of the Company's proposed streetlighting capital expenditures.

A. The Company's primary objective regarding streetlighting is to provide reliable service at the lowest reasonable cost to customers. The Company carries out this objective through conversions of older technology upon failure, installation of energy efficient lighting in new applications, and use of self-service technology, which reduces work processing and keeps the customer informed of streetlight outage status.

The Company is realizing the benefits of LED conversions through reduction of failed streetlight orders. The workplan laid out in the Reliability Roadmap will only accelerate this reliability benefit.

Performing cobrahead and post top LED conversions on a reactive basis provides customers with LED lighting in a fair and timely manner, without the upfront costs.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

DANIEL A. SCHMOEKEL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Daniel A. Schmoekel, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Daniel A. Schmoekel who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes. However, I have a new role. In September, I was promoted to Director of Engineering - LVD Statewide Programs. In this role I have responsibility for Streetlighting, low voltage distribution ("LVD") Resource Planning, Infrastructure Attachments, and Statewide Integration.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut a recommendation made by Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Jessica Duell. Specifically, I will provide rebuttal to Ms. Duell regarding her recommendation regarding the sufficiency of the Company's responses to discovery questions sent by Staff.

Q. Are you sponsoring any exhibits?

A. No.

Q. Have you reviewed the direct testimony of Ms. Duell?

A. Yes.

I. SUFFICIENCY OF THE COMPANY'S RESPONSES TO DISCOVERY QUESTIONS

Q. Beginning at page 15, line 15 of her direct testimony, Ms. Duell states "Staff recommends that the Company be more descriptive and detailed when replying to discovery questions sent by Staff." How do you respond to that recommendation?

A. I don't agree with the suggestion that Consumers Energy was insufficiently descriptive or detailed in its discovery responses to Staff, including the Company's response to discovery question U21870-ST-CE-0131 which Ms. Duell identified specifically. As stated by Ms. Duell starting on page 15, line 20, through page 16, line 3, in her direct testimony, the Company spent the remaining $1,056,000 of streetlighting budget on distribution capital investments.

Regarding Electric Distribution capital programs, the Company generally returns budgeted program funds that are unused to an Electric Distribution department level account. Funds are then reallocated to fund programs with additional capital needs in other parts of the electric distribution organization. However, specific dollars are not traced from one program to another. A reason for utilization of this method is that unused funds in one program and capital needs in other programs often occur at different times. As a result of this process, there were no more details the Company could have provided in response to Ms. Duell's question.

Q. Beginning at page 16, line 6, of her direct testimony, Ms. Duell states "In MPSC Case No. U-21585 the Commission ordered the Company to 'provide the Commission Staff with as much detail as possible regarding the application of excess funds for Streetlighting'. Unfortunately, the Company did not follow the order." Do you agree?

A. No. The Company is in compliance with the Commission's Order in Case No. U-21585. Again, specific dollars are not traced from one program to another. A reason for utilization of this method is that unused funds in one program and capital needs in other programs often occur at different times of the year.

The Company provided Staff with as much detail as possible regarding the application of excess funds for Streetlighting in all relevant discovery responses. The Company cannot provide detail that does not exist.

Q. What is your recommendation?

A. The Commission should reject Ms. Duell's claim that the Company failed to follow the Commission's Order in Case No. U-21585. That claim is untrue. Pertaining to the example referenced in Ms. Duell's testimony, discovery response U-21870-ST-CE-0131, unused funds in one program and funding of capital needs of other programs often do not occur at the same time.

As shown in Ms. Duell's direct testimony, page 15, line 20, through page 16, line 3, the Company demonstrated that unused streetlighting funds were allocated to distribution capital spending. There are no further details to share.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Next company witness, Andrew R Snider. Mr. Snider had revised direct testimony consisting of a cover page and 46 pages of questions and answers. He also had rebuttal testimony consisting of a cover page and 14 pages of questions and answers and Mr. Snider had no exhibits.

THE COURT: Is there any objection to the admission of this testimony?

Hearing none. The direct revised and rebuttal testimony of Andrew Snider is bound into the record.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REVISED DIRECT TESTIMONY

OF

ANDREW R. SNIDER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew R. Snider, and my business address is 4000 Clay Ave, Grand Rapids, Michigan 49548.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Electric Operations.

Q. Please describe your educational background and work experience.

A. I have a Bachelor of Business Administration from Davenport University in Grand Rapids, Michigan. I have been in the electric utility industry for more than 25 years. I began my full-time career with Consumers Energy in 1999 as an electric distribution designer and dispatcher. Through career progression in the Company's Engineering and Operations departments, I currently serve as Executive Director of Electric Operations, with responsibility for Customer Field Services, Electric Meter Operations, Underground Construction, and Contract Management teams. I have been directly involved in service restoration activities, fulfilling nearly all back office and leadership roles within the storm restoration/Incident Command System ("ICS") process dating back to my internship in 1998, supporting a back-office role for the largest storm in Company history. I served as a subject matter expert and project team member for the Outage Management System (OMS")/Responder project in 2008. I had the opportunity to represent Consumers Energy working on Florida Power and Light's system following Hurricane Wilma, and on National Grid's system following a severe winter storm. Today, I am supporting the Company's initiatives to improve service restoration activities.

Q. What are your responsibilities as Executive Director of Electric Operations?

A. I am responsible for leading Customer Field Services, Electric Meter Operations, Underground Construction, and Distribution Contractor teams.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I was the Company's witness for Service Restoration expense in Case No. U-21585.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's projected service restoration spending, including technology and process enhancements. The test year is defined as May 1, 2026 through April 30, 2027. In the test year, the Company projects $165 million in service restoration operating and maintenance ("O&M") expense, which is based on the Company's actual 2024 Service Restoration expense, adjusted for inflation. The projected test year expense is detailed further in the Service Restoration Test Year O&M Expense beginning on page 20. Company witness Patrick D. Daly sponsors the inflation rates. The service restoration O&M expense and O&M expense associated with the Control/Dispatch Center consolidation project are included in Company witness Michael P. Kelly's Exhibit A-124 (MPK-14), and the Control/Dispatch Center consolidation capital costs are included in Company witness Quentin A. Guinn's Exhibit A-102 (QAG-3). Information Technology costs addressed in my testimony are included in Company witness Stacy H. Baker's Exhibit A-12 (SHB-4), Schedule B-5.1, line 3.

Q. Have you prepared any exhibits in conjunction with your direct testimony?

A. No. I am not sponsoring any exhibits in conjunction with my direct testimony.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. SERVICE RESTORATION OVERVIEW AND RECENT TRENDS

II. LIBERTY AUDIT OVERVIEW FOR SERVICE RESTORATION

III. SERVICE RESTORATION TEST YEAR O&M EXPENSE

IV. SERVICE RESTORATION RESILIENCY FUND

V. EXTRAORDINARY STORM ACCOUNTING

VI. TECHNOLOGY ENHANCEMENTS

VII. PROCESS IMPROVEMENTS TO BETTER IDENTIFY OUTAGE CAUSES

VIII. CONTROL/DISPATCH CENTER CONSOLIDATION

I. SERVICE RESTORATION OVERVIEW AND RECENT TRENDS

Q. How does the Company's service restoration program benefit customers?

A. Following service interruptions, the Company is committed to restoring service to customers quickly and safely, regardless of the weather. Service restoration activities play a critical role in the timely restoration of service to customers during outages. Timely recovery of service restoration expense is essential to ensure resources are available to restore service as quickly as possible, as the Company will be challenged to achieve further improvements in storm restoration service if it does not have timely rate recovery for the costs associated with such service.

Q. The Company has been challenged by stakeholders to improve restoration efficiency. Has the Company been able to demonstrate results?

A. As predicted by our climate change and weather modeling, customers experienced another record-breaking year in terms of response opportunities. The volume of interruptions in 2024 exceeded what mother nature delivered in 2023. In 2024, three catastrophic storms

and two large gray sky events that occurred back-to-back in January, affecting 293K customers in one week, were the primary events. Despite the increase in storm activity and interruption volume, O&M service restoration costs decreased year-over-year from 2023 to 2024 by 17% with the cost per interruption decreasing by 18%.

Additionally, the Company's System Average Interruption Duration Index ("SAIDI") excluding Major Event Days ("MEDs") improved 21.4 minutes to 155, and all-weather SAIDI improved from 913 to 502.6 minutes. The improvements in service restoration are a result of both the distribution system investments sponsored by Company witness Kelly and the CE-Way process of continuous improvement that I discussed in detail in Case No. U-21585, and as shown in further detail in Figure 1 below.

Figure 1
2023 – 2024 Service Restoration Performance

Metric	2023	2024	Percent Change
Total Interruptions	50,700	53,900	6%
Percent Restored within 24 Hours	87%	94%	8%
Service Restoration Expenses	$188 M	$156 M	-17%

Q. How was the Company's service restoration performance in Environmental Justice ("EJ") communities in 2024?

A. In 2024, the Company's All-weather service restoration performance, restorations made within 36 hours, in EJ communities was 98.9% compared to 97.7% in Non-EJ communities. All-weather restoration performance in EJ communities in 2024 was 1.2% better than the Company's system average.

Figure 2
2024 Restoration Performance in EJ and Non-EJ Communities

Restoration Performance Metric	Non-EJ Communities	EJ Communities
Average percentage of all-weather restorations made within 36 hours	97.7%	98.9%
Average percentage of Catastrophic restorations made within 48 hours	95.4%	94.9%
Average percent of gray sky restorations made within 24 hours.	94.5%	93.2%

Q. Has the Company started to incorporate considerations for EJ in their restoration practices?

A. Yes. In March of 2025, the Company developed reporting to provide increased visibility into the identification of circuits in EJ communities that are experiencing outages. This information is available in real time to the ICS teams and Grid Operators to assist with restoration prioritization.

Q. Is the Company satisfied with its holistic 2024 historical year performance?

A. The Company is proud of the more efficient use of service restoration expenses and quicker restoration times in 2024, but has several approaches aimed at further enhancing its performance that are detailed later in my testimony. The Company acknowledges that even with strong improvement in 2024, customers deserve an even more reliable grid than the Company had last year.

The Company, including the Service Restoration team that I'm part of, has a more aggressive goal for reliability as detailed in the Reliability Roadmap, which includes three resiliency stands.

1. Delivering reliability performance into the 2nd quartile of nationwide utilities.

2. Delivering a grid where no single outage event will affect more than 100,000 customers.

3. Delivering a grid where no customer will be without power for more than 24 hours following an outage event.

Achieving these goals remains a long-term work in progress; they serve as a useful guide to what the Company is building through this rate case.

Q. What weather challenges has the Company experienced so far in 2025?

A. The company has experienced two catastrophic storms already in 2025. Both storms affected more than 300,000 customers and occurred just six weeks apart. The first event was a historic multi-wave storm event that affected much of the state of Michigan from late March into early April that meteorologists from the National Weather Service called, "the worst ice storm in modern times."[1]

The event was so destructive that on March 31, Governor Whitmer declared a state of emergency in 10 counties in northern Michigan (Otsego, Oscoda, Montmorency, Presque Isle, Emmet, Charlevoix, Cheboygan, Crawford, Mackinac, and Alpena) and later extended the declaration to cover Alcona and Antrim counties. Several extreme weather factors, including freezing rain, damaging winds, thunderstorms, and 13 confirmed tornadoes made for a long and challenging restoration effort. Further detail on the timing and customer impact of the storms is detailed in Figure 3 below.

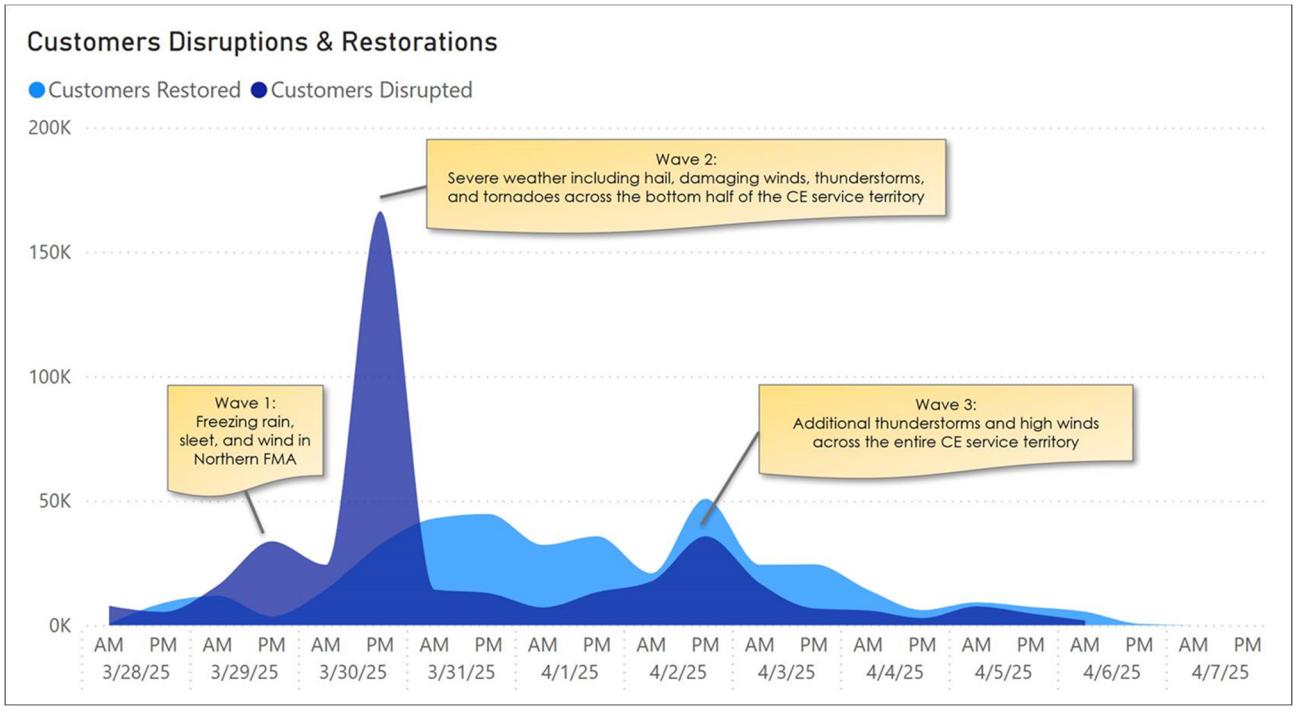
The event resulted in more than 8,500 outage incidents impacting over 380,000 Consumers Energy customers, the 7th largest storm by outages in the Company's history. Icing on distribution and transmission lines, measuring up to 1.5" in certain areas, began March 31 and remained into Thursday, April 3, continually bringing down trees, power

[1] Doyle, Annie. "'A Generational Storm': Northern Michigan Ice Storm Was Worst in over 100 Years." Petoskey News-Review, 3 Apr. 2025.

poles, and power lines, and delaying restoration crews' ability to make repairs due to the weight of the ice on the lines. The storm's severity and the subsequent evacuation of certain areas underscored the importance of Consumers Energy's enhanced Control Center Consolidation plan as discussed in section VII of my testimony.

The total cost of the storm is projected to exceed $133 million (O&M and Capital), which is a significant portion of the Company's 2025 service restoration authorized spend from Case No. U-21585.

Figure 3
March/April 2025 Catastrophic Storm Disruptions and Restorations



The second event affected over 334,000 customers just six weeks after the historic icing event. On the evening of May 15th, a severe line of thunderstorms struck the State, leaving a wake of destruction. The massive line of storms produced 11 tornados and hurricane strength wind gusts from Holland to Battle Creek, ultimately resulting in over

830 broken poles and 91 miles of conductor that required replacement. Total costs (O&M and Capital) from this event are estimated to exceed $60 million.

Q. What has the Company learned from the recent catastrophic storms in Michigan and how is this reflected in your testimony?

A. The recent catastrophic storms have demonstrated the urgent need for timely rate recovery to keep the power on for customers, businesses, and communities, so the Company can respond to the 'New Normal' of severe storms in Michigan.

The climate and weather modeling has been acutely prescient in predicting increased severe storms in the Company's service territory: the *Scenario and Investment Planning* section of the Reliability Roadmap included warnings of increased thunderstorms and 'Other' storms (including ice conditions) in the northwestern and southern parts of the Company's service territory, primarily occurring during the winter when outages are typically more difficult to restore.

The modeling goes on to predict that this type of weather will become more frequent in the coming years, meaning the Company will likely have to protect and restore its customers from similar events on a more regular cadence. My testimony lays out Consumers Energy's technological and operational initiatives to continue finding efficiencies as well as to ensure accurate restoration budgets and recovery of catastrophic storm spending through industry best practices.

Q. Please provide a brief overview of the remainder of your testimony.

A. Section II provides a detailed overview of Consumers Energy's current event classification, resource identification, and pre-storm communication as well as several other operational and budgeting recommendations from the audit conducted by Liberty Consulting Group

("Liberty"). Section III builds off the recommendations by Liberty, and details how the Company's bridge period and test year O&M was calculated in this case.

Sections IV and V include two new proposals to ensure the Company will have the necessary rate recovery needed to continue providing both timely storm restoration and a safe and reliable grid.

Sections VI, VII, and VIII detail the ongoing investments and process improvements being made to further foster Consumers Energy's storm restoration efficiency through upgrades to its digital emergency response system and consolidation of dispatch operations.

II. LIBERTY AUDIT OVERVIEW FOR SERVICE RESTORATION

Q. Please describe the process leading up to the audit performed by Liberty.

A. The Commission opened Case No. U-21305 in October 2022 after severe weather in August of that year caused many long power outages, downed energized utility lines across the state, and threatened public safety. In its order, the Commission instructed its Staff ("Staff") to hire a consultant to audit the electric distribution systems of Consumers Energy and DTE Electric Company. The Commission directed the audit to consist of physical inspection of the utilities' distribution system infrastructure and investigation of the utilities' organization, staffing, and resources used to operate and maintain their distribution systems and restore power when service is interrupted by severe weather. Staff hired Liberty to audit the two utilities' distribution systems, and the Company worked with Liberty to promptly answer all written questions and transparently meet in numerous interviews throughout 2023 and 2024. The Company also arranged Liberty's physical inspection and accompanied them as its auditors inspected pole locations, substations, the Cadillac headquarters, and the Jackson distribution center. Following this process, Liberty

released their final Utility Distribution Audit Report for the Company in two parts ("Final Report") on September 23, 2024.

In response to Liberty's Final Report and stakeholder comments, the Company filed comments and replies. Many recommendations in Liberty's report were aimed at improving the Company's service restoration performance and had obvious merit, which led the Company to begin making changes addressing these recommendations while it awaits a final order in Case No. U-21305. As these changes impact proposals and expenses in this case, I am updating stakeholders and the Commission on the Company's progress.

Q. Please describe the findings related to Pre-Event Planning from the Final Report.

A. Part II of the Final Report included three recommendations specific to Pre-Event Planning beginning on page 116, including:

- **Recommendation 4**: Better assure more tailored and accurate outage modeling results by codifying and analyzing predicted versus actual outage events.
- **Recommendation 5**: Classify weather events no later than when the decision is made as to whether available field resources will need to be supplemented and as early as data permits a reasonable assessment of a weather event's impact.
- **Recommendation 6**: Capture and analyze data associated with external resource requests. [2]

Q. Please provide further details on Liberty Recommendation 4.

A. Recommendation 4 proposes the Company evaluate its current outage model for effectiveness and consider developing a more robust product in-house or through a third-party vendor to provide more useful and impactful results.

[2] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 116 (Sep. 23, 2024).

Q. How has the Company's Service Restoration responded to concerns raised by Recommendation 4?

A. The Company agrees with the Final Report recommendation that accurate outage modeling is critical for restoration staffing and planning for forecasted storm events and believes that more accurate outage predictions can improve the Company's storm restoration performance, including wire-down response.

The Company is currently working to improve its outage modeling results through two additional initiatives, which will enable the Company to make improvements in outage modeling capabilities:

- **New Third-Party Outage Model** – The Company is currently evaluating third-party vendor technologies that could potentially improve upon its outage modeling capabilities currently provided by IBM. The Company is currently in a request for proposals phase with third-party vendors, which would merge its weather and outage modeling services. The Company expects to select a third-party provider in May 2025, and the Company expects that it will be able to leverage the outputs of the third-party vendor's model later in 2025.

- **New In-House Outage Model** – The Company plans to internally develop a standalone outage prediction model in partnership with the University of Michigan. This in-house model would provide the Company with another set of data to compare against outputs from the third-party outage model. Currently, this model development is in its preliminary stages and is scheduled to be operational by late 2025. Once developed, the Company would run the in-house model concurrently with the third-party vendor model to compare results and test its output to determine the in-house model's effectiveness and for potential upgrade and/or waste elimination opportunities. In the testimony of Company witness Scott A. McPhail, weather stations will be added to provide more granular weather data that will eventually feed into the in-house outage model offering improved predictive capabilities.

In summary, the Company agrees with this recommendation and has a series of technology investment plans that will enable the Company to improve its outage modeling prediction accuracy beginning in 2025. Furthermore, the Company will continue to assess the

predictions from these capabilities against actual outages to identify areas of improvement to drive better prediction outcomes for future storms.

Q. Please provide further details on Liberty Recommendation 5.

A. Recommendation 5 proposes the Company make the act of event classification a catalyst to groups involved in restoration to prepare to address the needs associated with the anticipated impacts of the event and change, as necessary, after storm arrival, to reflect new weather-related developments and resultant changes.

Q. How has the Company's Service Restoration responded to concerns raised by Recommendation 5?

A. The Company has appropriate processes and procedures in place to meet the intent of this recommendation. The Company understands the intent of this recommendation is to enable efficient storm restoration preparation performance by potentially improving early storm event classification, resource needs identification, and pre-storm communication processes and procedures. While the Company welcomes opportunities to improve its storm response preparation processes and procedures, there is more to the Company's current processes than what is reflected in the Final Report for event classification, resource identification, and pre-storm communication.

Q. What is the Company's current process for event classification, resource identification, and pre-storm communication?

A. When preparing for a storm, the Company predicts an estimated number of outages from its current IBM outage prediction model that will be experienced because of the potential storm event.

The next step is to use its Catastrophic Crewing ("CatCrew") tool to develop an estimate of how many resources will be needed to complete the restoration within the MPSC's Service Quality and Reliability Standards for Electric Distribution Systems. Based on this outage prediction and estimated resource needs, the Emergency Response team then makes and communicates an event classification for the potential storm event. On page 95 of the Final Report in Part II, Liberty included a table with the storm incident classification levels from the Company's Storm Restoration Manual ("SRM"). Initial storm classifications are documented on an ICS Form 201 for each storm event, which is available to all storm responders in the ICS organization.

Q. Concerning the Company's current event classification and resource identification processes, what else should stakeholders and the Commission know when evaluating the Final Report findings on these issues?

A. There are several aspects of the Company's current event classification and resource identification processes and procedures that should be considered:

- Part II of the Final Report states on page 96 that "Analysis showed that management did not classify any of these events prior to event start date."[3] All initial storm classifications are documented on the ICS Form 201.

- The Final Report goes on to state on page 96 that "Consumers' event level classifications provide no specific guidance as to potential resource requirements." In fact, predicted customer outages and estimated resource needs dictate storm event classification; storm event classification does not dictate resource needs. In other words, storm event classification can only happen when resource needs and customer outages have been estimated. Additionally, the model being developed by the Company in partnership with the University of Michigan will use sophisticated machine-learning techniques to correlate historical outages to their causation (i.e., weather, topographic data, forestry work, reliability work, etc.). This will produce a more accurate and more localized outage forecast due to incoming weather that allows better planning to secure and pre-stage resources for faster restoration.

[3] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 96 (Sep. 23, 2024).

- Part II of the Final Report states on page 113 that "The storm team communicates internally to activate the required resources and processes without attaching value or significance to the determination and communication of an event's classification. This view should change."[4] The value and significance of a storm event is the predicted customer outages and estimated resource needs, not the storm incident level by itself. While storm event classification may be useful as a trigger for certain storm related activities, the predicted customer outages and estimated resource needs is the foundational information that drives all storm restoration related activities.

Q. Please provide more details on the Company's current storm communication process.

A. The Company currently plans for storm events on a weekly basis in advance to prepare for a weather event's impact and communicates accordingly with its stakeholders. As recommended in the Audit, in November 2024 the Company hired a full-time Meteorologist to provide tailored weather forecasts, specific to the Company's distribution grid and the state of Michigan, every morning to stakeholders across the Company. In terms of timing, every week the Company prepares for the subsequent week's potential storm responders from an ICS perspective. This cadence includes an initial indication of what ICS Level the storm may be based on meteorological forecasts. Storm preparedness communications begin every Thursday and storm preparation related information is documented in ICS Form 201. Additionally, every day there is a Daily Communication Report that provides storm preparation and planning updates to relevant stakeholders across the organization. This information includes any changes to initial forecasts and updates to previous resource needs.

[4] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 113 (Sep. 23, 2024).

Q. Concerning the Company's current storm communication processes, what else should stakeholders and the Commission know when evaluating the Final Report findings on this issue?

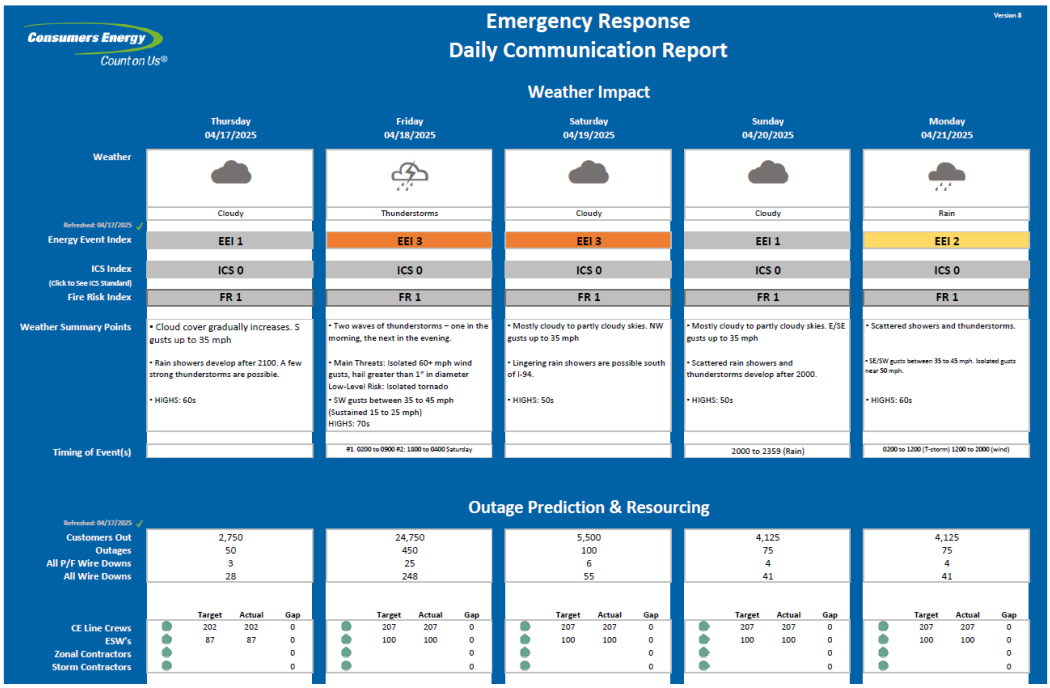
A. There are several aspects of the Company's current storm communication processes and procedures that should be considered:

- Again, Part II of the Final Report states on page 96 that "Analysis showed that management did not classify any of these events prior to event start date. Neither did it change any classification for these events once made.[5]" As described above, storm event preparation and planning updates are communicated daily to all stakeholders via the Daily Communication Report. Based on changes communicated in this report, including event classification changes, appropriate storm response related actions are made. The Final Report does confirm this in another statement on page 96 that "Restoration Management did . . . begin in late 2023 to publish a Daily Communication Report that presents a five-day look ahead that contains, among other useful information, outage prediction and resource requirement data and an ICS incident level prediction. See Figure 4 below."[6]

Furthermore, the Company does correct the ICS Level categorization data when it is finalized for MPSC reporting purposes. For example, if a storm is initially reported as affecting an estimated 190,000 customers and subsequent meter-ping data determines that only 180,000 customers were affected, that information will be shared with the MPSC as well if there is a relevant incident level adjustment. These updates are done across normal, gray sky, and catastrophic storm conditions.

[5] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 96 (Sep. 23, 2024).
[6] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 96 (Sep. 23, 2024).

Figure 4
Daily Communication Report Example



Emergency Response
Daily Communication Report

Version 8

Weather Impact

	Thursday 04/17/2025	Friday 04/18/2025	Saturday 04/19/2025	Sunday 04/20/2025	Monday 04/21/2025
Weather	Cloudy	Thunderstorms	Cloudy	Cloudy	Rain
Energy Event Index	EEI 1	EEI 3	EEI 3	EEI 1	EEI 2
ICS Index (Click to See ICS Standard)	ICS 0	ICS 0	ICS 0	ICS 0	ICS 0
Fire Risk Index	FR 1	FR 1	FR 1	FR 1	FR 1
Weather Summary Points	• Cloud cover gradually increases. S gusts up to 35 mph • Rain showers develop after 2100. A few strong thunderstorms are possible. • HIGHS: 60s	• Two waves of thunderstorms – one in the morning, the next in the evening. • Main Threats: Isolated 60+ mph wind gusts, hail greater than 1" in diameter Low-Level Risk: Isolated tornado • SW gusts between 35 to 45 mph (Sustained 15 to 25 mph) HIGHS: 70s	• Mostly cloudy to partly cloudy skies. NW gusts up to 35 mph • Lingering rain showers are possible south of I-94. • HIGHS: 50s	• Mostly cloudy to partly cloudy skies. E/SE gusts up to 35 mph • Scattered rain showers and thunderstorms develop after 2000. • HIGHS: 50s	• Scattered showers and thunderstorms. • SE/SW gusts between 35 to 45 mph. Isolated gusts near 50 mph. • HIGHS: 60s
Timing of Event(s)		#1. 0200 to 0900 #2: 1800 to 0400 Saturday		2000 to 2359 (Rain)	0200 to 1200 (T-storm) 1200 to 2000 (wind)

Outage Prediction & Resourcing

	Thursday 04/17/2025	Friday 04/18/2025	Saturday 04/19/2025	Sunday 04/20/2025	Monday 04/21/2025
Customers Out	2,750	24,750	5,500	4,125	4,125
Outages	50	450	100	75	75
All P/F Wire Downs	3	25	6	4	4
All Wire Downs	28	248	55	41	41

	Target	Actual	Gap	Target	Actual	Gap	Target	Actual	Gap	Target	Actual	Gap	Target	Actual	Gap
CE Line Crews	202	202	0	207	207	0	207	207	0	207	207	0	207	207	0
ESW's	87	87	0	100	100	0	100	100	0	100	100	0	100	100	0
Zonal Contractors			0			0			0			0			0
Storm Contractors			0			0			0			0			0

Q. Please provide further details on Liberty Recommendation 6.

A. Recommendation 6 proposes the Company track resource requests from specific contractors (or mutual assistance), request timing, and what resources were provided to assist in post-event analysis, process improvement, and internal training.

Q. How has the Company's Service Restoration responded to concerns raised by Recommendation 6?

A. Since the execution of Consumers Energy's storm contracts which began on June 1, 2023, the Company has implemented or refined mechanisms to track, manage, and retain requests for resources to respond to service restoration events. These mechanisms include:

- A scorecard of all storm contractors to assist in acquiring resources by ranking the storm contractors in terms of lowest cost, proximity to Jackson, MI, number of full-time employees ("FTE") available to respond, and union/non-union status of their FTE's.

- A managed PO Box where all communications pertaining to requests for assistance are kept.

- Centralized Microsoft Teams database maintained by the Company's Emergency Response organization. This database contains all current and past storm rosters of storm response contractors acquired since January 2022 to present, training standards, and documentation for Contractor Personnel Specialists responsible for acquiring storm response contractors.

- Bi-annual training for Contractor Personnel Specialists, along with on-demand training as standards are updated or improved.

- Ensuring the Company's storm response contractors have completed Consumers Energy's requirements for onboarding in ISNetworld prior to arrival on the system.

- Developing, designing, and delivering training to Company representatives responsible for oversight of storm contractors, including daily validation of crews and equipment acquired and working on Consumers Energy's system.

Q. Please describe the findings related to restoration budgeting from the Final Report.

A. Part II of the Final Report included two recommendations specific to restoration budgeting beginning on page 117[7]:

- **Recommendation 9:** Re-baseline restoration budgeting to produce estimates that fully and realistically consider expected needs; and

- **Recommendation 10:** Explore means to balance Company and customer interests in addressing highly volatile restoration costs following completion of the preceding recommendation addressing budgeting for storm restoration.

Q. Please provide further details on Liberty Recommendation 9.

A. Liberty's Recommendation 9 is a result of their Conclusion 15 in Part II, Chapter III, pages 114 to 115 which concludes:

> It is not clear how a five-year average serves as a sound basis for setting budgets or a meaningful marker for sharing restoration costs that vary from five-year averages. [8]

[7] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 117 (Sep. 23, 2024).
[8] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, pages 114-115 (Sep. 23, 2024).

Recommendation 9 states that reliance on the five-year average to fund service restoration should end.

> Reliance on five-year historical costs to establish restoration budgets should end. Those responsible for managing restoration cannot be held properly accountable for work or costs performance if established budgets are known to be unrealistic, fail to account for weather volatility, include anomalous weather years within the five-year measurement period, or rely on contributions from other parts of the organization to accommodate not just expected, but essentially certain overruns.[9]

Recommendation 9 also proposes the Company address how these system investments and weather conditions will change through the timeframe included in the Reliability Roadmap report.

Q. Please provide further details on Liberty Recommendation 10.

A. Recommendation 10 notes that service restoration expenses should theoretically trend downward in response to reliability and resiliency investments. However, those improvements may be offset by worsening weather:

> Most significantly, the use of five years of historical restoration costs as a benchmark for sharing between the Company and customers ignores the fact that the system will steadily respond better as time passes to outages that require material restoration. It should not be taken for granted that escalation and worsening weather will overcome the reliability and resiliency gained by billions of dollars spent over that historical period….[10]

Short of completing a full analysis that normalizes weather conditions and quantitatively assesses how the Company's investments will interact with weather conditions to impact storm restoration costs, as Liberty suggested in Recommendation 9, Recommendation 10

[9] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 117 (Sep. 23, 2024).
[10] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 118 (Sep. 23, 2024).

includes a deferral alternative. Liberty noted that other state regulatory commissions have found deferral an effective means for permitting recovery of excess storm costs coupled with a reasonableness and prudence review.

Q. How is the Company's Service Restoration proposal responsive to concerns raised by Recommendations 9 and 10?

A. The Company's proposed bridge period and test year O&M expense aligns with Final Report recommendations by ending reliance on a five-year historical average and instead basing the projected expense on the Company's 2024 actual Service Restoration expense adjusted for inflation. The Company believes this approach provides the most accurate benchmark based on projected service restoration performance requirements. The Company's Reliability Roadmap, included as part of this case as Exhibit A-129 (MPK-19), already provides a normalized weather modeling forecast for the three scenarios recommended by the Final Report. Further detail on the projected O&M spend, based on 2024 actuals, is included in the following section of my testimony.

III. SERVICE RESTORATION TEST YEAR O&M EXPENSE

Q. What is the Company's projected service restoration O&M expense for the test year in this case?

A. The Company's projected service restoration O&M expense for the bridge period is $214.3 million and the projected expense for the test year in this case is $165.2 million as shown in Exhibit A-124 (MPK-14), line 22.

Q. How did the Company determine this amount for projected service restoration O&M expenses for the test year?

A. Part II, Chapter III, page 110 of the Final Report states that:

> Consumers plans very large capital and O&M expenditures to improve system reliability and resiliency over the course of five years. It has already achieved improvements to date. Those improvements should, all else being equal, lower restoration costs for a system steadily and materially improving in reliability and resiliency, **making historical costs a lagging, and not a leading indicator of likely costs.** Factors that make all else unequal include escalation that will affect the unit cost of each piece of equipment installed and each quantity of work performed. Should recent storm frequency and magnitude trends reverse, more extreme weather will also drive costs upward, albeit moderated by an increasingly "strong" system. Storm restoration costs have proven highly volatile throughout the industry.[11]

Given that 2024 O&M spending is a lagging indicator (although with far less lag than the five-year average), the bridge period and test year funding was calculated by inflating the historical year 2024 for the years 2025, 2026, and 2027. For the bridge period, the calculation includes all of calendar year 2025, plus four months of 2026, the sum of which equals the bridge period amount of $214.3 million. The calculation for the test year considers eight months of the year 2026 and four months of the year 2027, the sum of which equals the test year amount of $165.2 million. The inflation rates for the years mentioned above are sponsored by Company witness Daly.

[11] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 110 (Sep. 23, 2024) (emphasis added).

Q. What is the most recent five-year average for Service Restoration, and would that amount be adequate for the Test Year in this case?

A. Service Restoration has been underfunded in each of the previous five years, for a total funding gap of $351 million. The most recent five-year average from 2020 through 2024 would have produced a test year total of approximately $148 million that the Company projects would be insufficient to deliver the improved service restoration that customers deserve. To illustrate the point, the March/April catastrophic storm that I described earlier is projected to cost at least $133 million dollars combined O&M and Capital. As explained in detail in Section I of my testimony, the actual expenses from the calendar year 2024 were $156 million, which were sufficient for the Company to deliver improved performance on all restoration metrics. As the Company faces increasingly severe weather, and progressive service restoration improvement metrics detailed in the Commission's February 27, 2025 Order in Case No. U-21400, relying on a backward-looking average that has been explicitly rejected by an independent audit threatens to undo the progress made by the Company.

Q. Why are 2024 historical costs a reasonable benchmark for projected service restoration expense?

A. Prior year spending is the most accurate benchmark of trending weather and current system capabilities, based on the unpredictable weather explained in the *Scenario and Investment Planning* section of the Company's Reliability Roadmap beginning on page 18. This fact is recognized in the order released on March 13, 2025 in Case No. U-21400 where the Commission decided to benchmark all weather SAIDI on current year performance rather

than the five-year average, as current year performance better reflects recent trends and customer experience.[12]

A study, beyond the Reliability Roadmap, specific to annual restoration spending, would be theoretical given the high volatility of key variables. The Company's recommended approach is to re-baseline to the most recent year, which most accurately represents all variables in their current state. Further, through the creation of the Resiliency Fund outlined in Section IV, the Company ensures every dollar is allocated specifically for customer service restoration or returned to customers as a credit.

Q. Has the Company been prudent with restoration dollars by increasing efficiencies?

A. Yes. The Company's results are demonstrated by its historic year's performance and documented in Service Quality and Reliability Standards filings and discussed in Section I of my testimony. In 2024, the duration of catastrophic storms in the Company's service territory, as measured by the average length of storm days, was 3.3 days compared to a five-year average of ~~5.4 days~~ 5.5 days. This accounts for a 2.1 day or 61% reduction in catastrophic storm duration resulting in a greatly improved customer experience.

Liberty also took note of our performance trend since 2017 concluding in Part II, Chapter III, Pages 113 through 114 of its audit:

> Consumer's restoration performance, measured by the average duration of classified storm types, **shows marked improvement in recent years across all storm classifications except for Catastrophic.**[13]

[12] See Case No. U-21400, February 27, 2025 Order, page 30 ("The Commission agrees that performance on this [all-weather SAIDI] metric should be measured for the previous year only.")
[13] Case No. U-21305, Liberty Audit Final Report Consumers Energy Part II, page 113-114 (Sep. 23, 2024) (emphasis added).

In terms of catastrophic performance, and the data set studied by Liberty, recent storms had caused more customer interruptions resulting in longer durations trends through 2023. Liberty noted in Part II, Chapter III, page 110:

> A Catastrophic storm's defining characteristic, a minimum of 10 percent of customers affected, ensures a longer restoration period as compared with those of smaller storms. The unbounded upper limit on customers affected also tends to produce a much greater variation in the numbers of affected customers. The much longer duration of Catastrophic storms and greater variations in duration therefore come as expected.[14]

Q. How does the Company's proposal align with the Liberty Audit recommendations for Service Restoration?

A. As mentioned earlier in my testimony, the proposed test year O&M proposal reflects the 2024 actual Service Restoration expense adjusted for inflation, which the Company believes provides the most accurate benchmark for service restoration requirements.

IV. SERVICE RESTORATION RESILIENCY FUND

Q. What is the Service Restoration Resiliency Fund?

A. The Resiliency Fund ensures that every customer dollar allocated for service restoration is used for service restoration or returned to customers as a credit. The Resiliency Fund is a reserve of surplus service restoration dollars from any prior year that will be used as the first source of funds when actual costs for service restoration exceed base spend levels. The fund will be capped at $30.7 million in the test year, with any dollars exceeding those levels refunded to customers through a bill credit.

[14] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 110 (Sep. 23, 2024).

Q. Please provide an example of how this fund would operate.

A. If this fund is approved, any unspent dollars from the approved amounts for the test year would be transferred to the Service Restoration Resiliency Fund. Those dollars can be used to support service restoration expenses in future years when additional funds are needed and would function as the first option to fund any restoration activity beyond base funding levels. Please see Company witness Foster's testimony on page 15 for more detail on the accounting of this request.

Q. Please walk through Scenarios 1, 2, and 3 from Figure 5 below.

A. **Scenario 1** shows an underspend of $40 million dollars in the test year resulting in a transfer of $30.7 million to the Resiliency Fund and a customer refund of $9.3 million. Since the Resiliency Fund cap is exceeded by this underspend amount, the remaining $9.3 million will be refunded to customers.

Scenario 2 shows an underspend of $20 million dollars in the test year resulting in a transfer of $20 million to the Resiliency Fund to be used for service restoration expenses that exceed base spending. Since the Resiliency Fund cap is set at $30.7 million, the Resiliency Fund can accrue an additional $10.7 million before there is a customer refund.

Scenario 3 shows an overspend of $5 million in the test year, resulting in no transfers to the Resiliency Fund.

Figure 5 - Resiliency Fund Year One Example

Scenario	Base Funding Amount	Restoration Spend	Resiliency Fund Balance	Customer Refund
1	$165M	$125M	$30.7M	$9.3M
2	$165M	$145M	$20M	$0
3	$165M	$170M	$0	$0

Q. How and why was the $30.7 million cap limit set?

A. The cap limit was based on the average O&M costs for a catastrophic storm for the past three historic years (2022, 2023, and 2024). The average storm cost was then adjusted for inflation based on the 2.4% inflation rate supported by Company witness Daly as part of this case. Because the weather is unpredictable, the Company set this limit to ensure that the fund only preserves the dollars needed to respond to a single potential catastrophic event, after which customers would see a financial benefit from the Company's efficiency.

Q. Is there a precedent from other states for setting a cap on reserve funds for storm restoration?

A. Yes. The Massachusetts Department of Public Utilities ("DPU") approved a proposal by National Grid to increase the available storm fund contribution to reflect average annual storm expenses for the previous five fiscal years. Under the recently revised proposal, for any storm in which National Grid incurs more than $1.80 million in incremental O&M costs, National Grid is permitted to access a storm fund for the deferred recovery and reimbursement of the portion of the costs that exceed $1.80 million up to $30 million for a single event. In its order approving National Grid's proposal, the DPU noted the proposed storm fund will provide for adequate recovery of storm costs while promoting rate stability. While the Company's proposal differs from the Massachusetts mechanism, which includes a surcharge to collect a set amount of storm costs through rates, the concept of setting a cap on funds reserved for future use is similar.

Q. How is this proposal different from how underspends for service restoration are handled currently?

A. Currently, in the event of an underspend for Service Restoration, the Company would re-allocate the O&M resources to other projects with no guarantee that customers would see any reimbursement. If approved, this Fund would both earmark approved funds for service restoration in the years to come when the need arises or be returned to the customer.

Q. What is the likelihood that there will be any underspend in the test year in this case?

A. Re-baselining suggests there is a higher likelihood of underspend. The Company knows that weather is unpredictable; however, as Liberty noted, weather volatility should be at least partially offset by system improvements.[15] Coupled with the Company's restoration improvements, the Company maintains that there is an increased likelihood of underspend from the prior year baseline. It really depends on what nature delivers. Consumers Energy estimates that, over time, reliability investments will ease restoration spending needs. When the Company inevitably spends less than projected, customers are protected by the designed nature of the Resiliency Fund.

Q. Why is the Service Restoration Resiliency Fund good for customers?

A. The Resiliency Fund comes at no additional cost to customers—it is simply a rainy-day savings plan. The Resiliency Fund ensures all dollars allocated for service restoration are spent on service restoration or refunded. This proposal, coupled with re-baselining Service Restoration to prior year actuals, mitigates the need for expensive speculative studies on how the system will perform given the multitude of variables, while ensuring that **all** savings from prior year system improvements and efficiencies will be saved for outlier

[15] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 115 (Sep. 23, 2024).

restoration expenses in a future year. Together with annual re-baselining, customers will see immediate benefits from any year's savings in the next baseline, while savings are also captured in the Resiliency Fund for no other reason than to benefit customers, literally, on a rainy day.

V. EXTRAORDINARY STORM ACCOUNTING

Q. Please describe the Company's proposed Extraordinary Storm Accounting or "ESA."

A. ESA allows the Company to use deferred accounting for service restoration costs for extraordinary storms that exceed base spending levels. The Company defines "extraordinary storms" as storms that cause at least 300,000 customer outages over a seven-day period or that result in a State of Emergency declaration from the Governor's office. A recent example of such a storm is the March/April catastrophic storm cited in Section I of my testimony. Under the Company's proposal, expenses in response to extraordinary storms would qualify for deferred recovery.

Q. Please provide an example of how ESA would operate.

A. If the Company experiences any emergency storm(s) described above that drives the actual spend higher than the service restoration base spending level (as well as any dollars available through the Resiliency Fund, if approved), the Company would seek deferred recovery from the Commission by demonstrating the reasonableness and prudence of the restoration expenses in a future rate case. Overspend costs not related to an emergency storm would not be eligible for recovery under ESA.

As detailed above, spending below the approved spending level would be directed back to service restoration or customer refunds through the proposed Resiliency Fund (if approved).

Q. How was the 300,000 customer outage over a seven-day period or State of Emergency declaration threshold determined?

A. The emergency storm threshold was designed to apply to uncommon storms, based on objective metrics or independent third-party assessment, which cause the most restoration work and costs to the Company. In reviewing historical restoration data, storms causing at least 300,000 customer outages are rare occurrences that also correlate to a long restoration time and high costs. The Company has only recorded 13 storms with at least 300,000 outages, and restoration efforts from those storms have averaged seven days in restoration duration.

While the outage count is a useful proxy for restoration time and cost, it is not the only indicator of damaging events. Isolated natural disasters, such as the tornadoes that struck Kalamazoo in 2023, did not cause many outages, but caused considerable damage to distribution assets, leading to a three-day restoration. The addition of an emergency declaration from the Governor's office allows for an independent assessment outside of the Company's control to also qualify an event as an "emergency storm."

Q. Why is the proposed ESA necessary?

A. Extraordinary storms, which present challenging restoration conditions and cause significant damage to Company assets, are the main cause of increased service restoration spending and pose the largest risk to sustainable service restoration operations. As explained earlier in my testimony, the March/April storms qualify as extraordinary storms that drained most of the service restoration O&M budget for 2025. When these storms pass through the Company's service territory, even perfect execution of pre-planning and restoration procedures can still result in a costly, multi-day restoration effort costing over

$100 million. As disruptive and costly as these storms are, they are fundamentally unpredictable; it is impossible for the Company to know with any degree of certainty how many of these storms will pass through its service territory, and therefore impossible to accurately predict the resources needed to respond to them. Requiring the Company to bear the full brunt of their impact in a single year without allowing for deferred storm accounting, which recognizes the heavy costs the Company incurs to safely and quickly restore power after extraordinary storms like these, is not only unreasonable but also counterproductive to ensuring a reliable and resilient grid. Preparing for a future where weather events like the March/April storms are more frequent requires establishing deferred accounting where the Company can apply for timely rate recovery in response to these events.

Q. What were the findings of the Liberty Final Report related to deferred recovery for excess storm costs?

A. Liberty noted the current utilization of deferral accounting by other commissions in Part II; Chapter III, Pages 118-119 of the Final Report, stating,

> Deferral accounting for excess storm costs may offer a solution for avoiding customer costs for adverse weather that does not materialize, while preventing significant Company economic loss when such weather requires significantly more than costs included in revenue requirements for ratemaking purposes. Other commissions have found deferral an effective means for permitting recovery following some form of reasonableness and prudence review that considers conditions faced and the effectiveness of efforts undertaken to address them.[16]

[16] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, pages 118-119 (Sep. 23, 2024).

Q. Do other states use deferred accounting for O&M costs caused by severe weather?

A. Yes. New Jersey is one example. In 2021, the New Jersey Board of Public Utilities ("BPU") authorized deferred accounting for storm costs in BPU Docket No. ER21050823, with automatic qualification for specific storms and the ability for utilities to petition for approval for other storms. The Board determined that the utilities' costs for an individual storm automatically qualify for deferred accounting if they incurred incremental costs of $300,000, and the storm caused 10% or more of the customers located in the service territory to be without electric service. South Carolina is another example. In response to standalone storms that devastated large portions of the Carolinas, the Public Service Commission of South Carolina in 2019 authorized deferred accounting for incremental storm damage expenses in Docket No. 2019-26-E.

Q. Please walk through Scenarios 1, 2, and 3 from Figure 6 below.

A. **Scenario 1** shows an overspend of $30 million, driven by a $50 million emergency storm and resulting in a $30 million deferred recovery request. Since the emergency storm costs exceed the difference between the base funding amount and the actual restoration spend, the Company will ask for deferred recovery for the difference. The Company will provide the Commission with the total expenses in response to the emergency storm including justification for their reasonableness and prudence.

Scenario 2 shows no difference between the base funding amount and the total spend. Since the calendar year budget was adequate to the restoration needs for the year, there will be no ESA despite the presence of an emergency storm.

Scenario 3 shows an overspend of $10 million but since the overages are not a result of an emergency storm, the ESA will not be available.

Figure 6
ESA Year One Example

Scenario	Base Funding Amount	Total Restoration Spend	Emergency Storm Costs	ESA Deferred Recovery Amount
1	$165M	$195M	$50M	$30 M
2	$165M	$165M	$50M	$0
3	$165M	$175M	$0	$0

Q. What is the process in a year where customers experience emergency storm(s) and spending is less than base funding?

A. All underspend in service restoration will be allocated to the Resiliency Fund up to the cap of $30.7 million. Once the cap is reached, customers will be refunded as a bill credit as described in section IV.

Q. What if the Resiliency Fund has a balance large enough to cover overages caused by catastrophic storms?

A. In this circumstance, the Company will not use ESA. Resiliency Fund dollars will be used first to supplement overages in restoration spending.

Q. Can ESA function independently without the Resiliency Fund?

A. Yes. ESA can function independently. If approved, the Resiliency Fund would serve as the first source of excess service restoration funds in the event of an overspend; however, it is not required for the Company's ESA proposal.

Q. How is ESA different from the Service Restoration Cost Sharing Mechanism ("SRCSM") proposed in Case No. U-21585?

A. ESA creates both a higher threshold for deferred recovery than the SRCSM as well as a process for Commission approval and vetting of service restoration expenses. ESA is only available for "extraordinary storms," defined to limit the eligible expenses for deferred accounting to storms that cause the most damage to customers and restoration work for the Company. By narrowing the scope of storms that qualify for deferred recovery, the Company can focus on meeting Commission-defined Service Quality and Reliability Standards within the base spending levels and have faith that timely rate relief will be available when needed. Secondly, ESA gives the last word on deferred recovery to the Commission. When deferred costs are considered for recovery in a future case, ESA will require the Company to demonstrate that all expenses in response to extraordinary storms are reasonable and prudent. The explicit inclusion of Commission approval is intentional and reflects the Company's confidence in its service restoration practices and desire for a collaborative process to address future emergency storms.

VI. TECHNOLOGY ENHANCEMENTS

Q. Are there any Capital investments in technology that support Service Restoration?

A. The Company is continuing to enhance the digital emergency response system by completing the previously planned CatCrew and Advanced Distribution Management System ("ADMS") enhancements, as approved in Case No. U-21389. The Company is also resolving the software obsolescence concerns of its integrated Tools for Operations Application ("iTOA"), as referenced on page 39 of Company witness Baker's testimony and Exhibit A-84 (SHB-1), as approved in Case No. U-21585 The Company is proposing a $825,700 capital and $660,500 O&M investment in the test year for the development of

machine learning / Artificial Intelligence ("AI") digital tools to specifically support storm response, as described on page 52 of Company witness Baker's testimony and Exhibits A-12 (SHB-4), Schedule B-5.1 and A-19 (SHB-3).

Q. How will the digital tools and utilization of Machine Learning and AI benefit customers?

A. The Company has developed several use cases where machine learning and AI can assist with faster and more consistent decision-making. Speed to execution is of critical importance during restoration events, and AI's unique availability to simultaneously evaluate multiple datasets and assist with decision-making will reduce non-value-added time during restoration. Furthermore, AI's learning abilities enable decision-making to continuously improve, are unaffected by turnover, and mitigate learning curves as people transition from role to role.

Q. What are the use cases for digital tools and AI?

A. **Storm Declarations:** The Company already has clear standards for when a storm should be declared based on system conditions and resource availability. The opportunity for this use case is to build a prototype learning model that continuously optimizes when storm activations occur. Many storm declarations are clear decisions when a major event occurs. However, this use case will specifically help with the "borderline" decisions on blue sky and gray sky days.

Resource Planning: The Company believes that AI can assist with modeling resource needs based on weather forecasts. Today, the Company estimates the number of interruptions and subsequent customer outages based on weather forecasts. AI could assist with resource planning and optimize the Company's resource plan in a learning model.

The savings opportunity for this use case is centered around the efficient utilization and mobilization of resourcing and precise pre-staging for events. The target is for the resource plan to match the event size, thereby creating savings for customers by ensuring the most efficient resource planning.

Resource Utilization or Crew Movements: The Planning and Operations branches of the ICS teams need to make critically immutable and important decisions at the onset of an event. Consumers Energy's initial response to an event is one of the largest indicators of success. In large and catastrophic storms, where many headquarters have significant resource needs and a limited resource pool, it's imperative the ICS teams quickly assess the needs of 30 electric headquarters and allocate the available resources in the most efficient manner. The allocation must consider the location of the resources in proximity to the damage, the qualifications of the resources, knowledge of the system, and regional complexity factors (vegetation density, snow cover, road infrastructure, voltage differences) as these all affect the speed of restoration. For example, due to customer density and geographic complexities, Grand Rapids recovers faster than West Branch given the near-term weather forecast. Thus, it is critical not to move resources out of an area with an imminent weather threat.

Consider a reality-based scenario with 400 pre-staged line crews, 200 available forestry crews, 200 available wire-down resources, all in various locations around the state, that need to be immediately allocated to 15 storm-affected headquarters. Statistically, there are a near infinite number of solutions, but only **one** of those solutions is the most efficient. The faster the "one" most efficient solution is identified, and crews are mobilized, the more customers benefit in terms of duration and ultimately cost.

The gravity of this use case is to optimize that decision-making so decisions are made faster and result in more efficient outcomes.

Asset Identification: In 2024, the Company developed an asset identification AI model that learned what problematic insulators on the HVD system look like. The model then examined photographs from aerial patrols to identify the structures containing the problematic insulators. A similar application could be applied to facility identification during storm restoration. With a simple photo provided by a customer, AI could quickly distinguish Company-owned facilities from third-party facilities and help prioritize wire-down response, for example. An AI application could improve public safety and response efficiency by routing resources faster to where they are most needed.

Q. Would the Company deliver on all the above AI use cases if granted the requested investment?

A. All these AI use cases would contribute to the Company's service restoration processes as forward-thinking, industry-leading tools. The capital investment needed to fund research and development of the outlined use cases is small compared to the potential benefits. The Company plans to prioritize these use cases in the order in which they are listed above. The Company would begin with the Storm Declaration use case because the model has fewer variables and would quickly move next to the resource planning and crew utilization opportunities. The Company estimates an annual opportunity of reducing each medium-to-catastrophic event by 4 hours, with an estimated savings of $4.5 million annually with the realization of all use cases.

Q. Does the Company have experience with Digital Tools and AI?

A. Yes. The Company has three strong examples of how digital tools and AI are benefiting customers each day. The examples include: the estimated time of restoration ("ETR") model used in the Company's outage map, the forestry workplan selection tool as discussed by Company witness Pamela L. Bolden, and the insulator identification project I have discussed.

VII. PROCESS IMPROVEMENTS TO BETTER IDENTIFY OUTAGE CAUSES

Q. How does the Company currently identify and classify outage causes on its system?

A. When restoring power and responding to outages, the Company's field employees diagnose the outage causes and classify them using the Institute of Electrical and Electronics Engineers' (IEEE) standard outage cause codes, including the following: animals, equipment, trees, unknown, and weather. While the Company utilizes the IEEE standard, it recognizes there are opportunities to improve by relying less on "weather" and "unknown" cause codes. More accurate outage cause code reporting will help the Company as it analyzes its restoration performance and yield better data quality as it prepares its next reliability roadmap.

Q. In its distribution audit report, what did Liberty conclude about how Consumers Energy identifies and classifies outage causes?

A. On page 84 of Part I of Liberty's Report, it observed that the "weather" cause code "masks the actual cause of outages like trees, lightning, or ice . . . ." Similarly, it said that the "unknown" cause code is not precise but nonetheless "accounts for 11 percent of total interruptions." Ultimately, on page 17 of Part II of Liberty's Report, it concluded that

"weather" and "unknown" cause codes "diminish[ ] the effective[ness] of the analysis of outage causes necessary to identify and optimize solutions to address them."

Q. Did the Company respond to these findings in its comments and reply comments in the distribution audit docket?

A. Yes, the Company agreed that there is value in reducing the use of "weather" and "unknown" cause codes and discussed the initiatives then underway to improve how it identifies and classifies outages. Among other things, the Company said that it planned to benchmark its performance against peer utilities and identify measures being taken in the industry to categorize outages. Further, to better comply with IEEE standards, the Company said it was making changes to training, controls, and other operational processes. For example, the Company revealed its plan to establish new quality assurance and quality control processes to monitor and improve how line crews, dispatchers, and other storm responders categorize outages in real time when responding to incidents.

Q. Do you have any updates on the Company's progress?

A. Yes, the Company has engaged a third-party consultant to conduct the benchmarking that the Company described in its comments; this benchmarking is in-progress as of May 2025 and on-track to be completed before end of 2nd Quarter. The Company plans to complete process changes, including new quality assurance and quality control processes, by the end of the year. More accurate outage data will help the Company better plan its resources to restore power after outages while also enabling better planning for its Reliability Roadmap.

VIII. CONTROL/DISPATCH CENTER CONSOLIDATION

Q. Is the Company following through with its plan to consolidate dispatch operations?

A. Yes. The Company is transitioning to consolidate operations.

Q. Have there been any adjustments to the plan?

A. Yes. The Company has been diligent in using the Plan-Do-Check-Act methodology with this project and has made enhancements to strengthen operational capabilities as a result. During the execution phase, it was identified through employee feedback that there was a risk of losing talent and that operational capabilities would be enhanced by staffing the back-up location, rather than maintaining an unstaffed back-up location. While the decision to staff the back-up location provides a better level of service and equitable cost avoidance, and SAIDI savings, it has changed the scope of the project.

Q. How are the operational capabilities enhanced by a staffed location that can serve as a back-up?

A. A staffed back-up location significantly boosts operational capabilities by providing a reliable contingency plan in case of disruptions at the other site. This set-up ensures continuity of operations by minimizing downtime and maintaining productivity to optimize safe and timely restoration for customers. The presence of trained personnel at each location allows for immediate response to emergencies, reducing the risk of operational delays. Additionally, it offers flexibility in resource allocation, enabling the company to adapt quickly to changing circumstances and maintain service levels. Overall, two fully staffed locations strengthen the Company's resilience and operational efficiency. Various companies have consolidated their control rooms into two manned centers for quick back-up. Independent research organizations have evaluated these strategies, highlighting benefits such as operational continuity, enhanced reliability, quick response, disaster recovery, and improved security.

Q. Please explain how staffing a back-up center increases operational capacity.

A. Foundationally, the Company cannot operate without redundancy and must maintain a back-up facility, which has always been part of its plan. Several intuitive benefits are realized by staffing the back-up facility.

- **Seamless Transition**: No recovery time required for the loss of critical systems at either facility, resulting in the seamless transition of operations without impacting customers.
- **Human Resource Diversity**: Consolidating all operations into one geographic location in the state requires a deep talent pool in one area. Sharing the staffing needs between two facilities, in different locations, enables a more diverse and deeper talent pool.
- **Operational Capabilities**: In emergency situations, the Company's dispatch centers can partially support each other, thereby enhancing operational efficiency to a limited extent. For instance, in early 2024, an emergency required the evacuation of one dispatch center. The remaining center was able to assume critical statewide dispatch responsibilities, maintaining some continuity in service restoration efforts, and mitigating prolonged customer outages. Similarly, during the severe weather event on April 2, 2025, tornado warnings led to the evacuation of one dispatch center. Within five minutes, the alternate center resumed ongoing storm restoration activities, preventing delays in service restoration for the Company's customers. These instances highlight the current back-up capabilities between the Company's dispatch centers. The ability to back up non-dispatch functions, typically associated with monitoring and controlling the electric grid at higher voltages, will be fully realized upon the final control center consolidation.

Q. Can you talk about the benefits that have already been realized from the work that has been completed and detail the changes from previous cases?

A. Customers have already benefited from $3.4 million of avoided costs and a 4.1-minute SAIDI reduction achieved during the transition and throughout 2024. Testimony in Case Nos. U-21389 and U-21585 anticipated these avoided costs and SAIDI reductions, as Company witnesses outlined the overall significant cost savings and SAIDI improvements. Initially, the Company planned to establish one fully staffed control center and one unstaffed back-up facility, which was expected to yield annual savings of $8.6 million and

reduce SAIDI by 15 minutes. The total project cost was estimated at $17.2 million, with a schedule spanning from 2023 to 2026.

The current filing proposes creating two fully staffed control centers, each capable of functioning as a back-up for the other. This change is expected to yield annual savings of $10.2 million and reduce SAIDI by 20.8 minutes. The total project cost is now estimated at $30.6 million, with a schedule spanning from 2023 to the first quarter of 2027. Additional information on the revised benefits can be found later in my testimony.

Q. What milestones of this consolidation project have been completed as of the end of 2024?

A. Milestones for this project can be grouped in three areas: Building & Facilities, Process Efficiencies, and Resource Preparedness.

- Building & Facilities:
  - Consolidated three dispatch centers into two, strategically located in Jackson and Grand Rapids.
  - Initiated asbestos removal and remediation efforts.
  - Developed conceptual plans and cost estimates.
  - Currently in the preparation phase for design and engineering.
- Process Efficiencies:
  - Expanded Jackson's operating hours from 16 hours a day, five days a week, to 24 hours a day, seven days a week.
- Resource Preparedness:
  - Merged three operating groups into two: High Voltage Distribution and Low Voltage Distribution, ensuring alignment with transitional roles.
  - Operational responsibilities were adjusted to enhance efficiency and ensure a smoother workflow. This approach helped maintain productivity and adapt to new processes more effectively. By redistributing tasks and roles, the team was able to minimize disruptions and optimize overall performance during the transition phase.

Q. Have any benefits been realized in 2024 because of the Control/Dispatch Center Consolidation project?

A. Yes, from January 1, 2024, to December 31, 2024, the Company achieved measurable benefits, including:

- Cost Savings: Avoided $2.483 million in service restoration costs.
- Cost Savings: Reduced $0.9 million in Grid Operations Labor costs.
- Improved Reliability: Reduced all-weather SAIDI by 4.1 minutes due to:
  - Shortened storm durations through enhanced storm readiness.
  - Fewer activations of ICS responders.

Following the 2023 consolidation of three Dispatch Control Centers into two, the Company adjusted operational boundaries, enabling both control centers to be fully engaged in storm restoration efforts from the onset of an event. This strategic change enhanced resource allocation, optimized service restoration, and lowered operational costs. The implementation of 24/7 operations at one dispatch center in 2024, coupled with continuous improvement initiatives, allowed the Company to leverage an expanded management span of control and boost productivity during service restoration.

The operational efficiencies implemented enabled the two remaining Control/Dispatch Centers to manage restoration efforts for larger-scale events more effectively than before consolidation. As a result, the need for ICS responder activations has decreased, further optimizing response efforts. Establishing two fully staffed facilities is essential to ensure redundancy, enhance resilience, and maximize the benefits of improved resource allocation and operational efficiency.

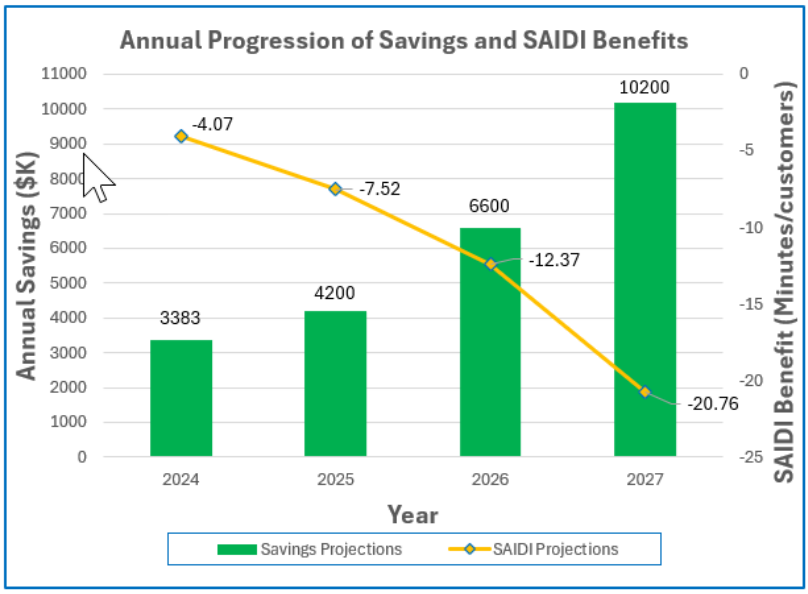
Q. What are the projected total cost savings and SAIDI improvements associated with this project?

A. Full benefit realization is projected by March 2028, one year following project completion. By this time, the Company expects to achieve:

- A sustainable reduction in all-weather SAIDI of 20.8 customer-minutes; and
- Annual cost savings of $10.2 million through avoided operational expenses.

Figure 7 illustrates the ramp-up of these benefits, including those already realized in 2024.

Figure 7
Control/Dispatch Center Consolidation Project Annual Progression of Benefits



Q. Were there any adjustments to the original benefits filed in Case Nos. U-21389 and U-21585?

A. Yes, there were adjustments to the original benefits filed in Case Nos. U-21389 and U-21585. The initial projections for the Control/Dispatch Center consolidation project have been refined based on historical data from 2022–2023 and the realized benefits in the

historical test year 2024. These adjustments were necessary to provide a more accurate and realistic estimate of the project's impact on service restoration and outage duration.

Figure 8 summarizes the projected cost savings and all-weather SAIDI benefits, with column (c) reflecting revised figures and column (a) displaying the original projections.

Figure 8
Control/Dispatch Center Consolidation Project Benefits

Line No.		(a)	(b)	(c)
		Original Benefits	**Adjustment**	**Revised Benefits**
1	Service Restoration Cost Reduction	$7.6M	$2.5M	$10.1M
2	Grid Operating Labor savings	$0.9M	Realized in 2024	$0M
3	Facilities / IT / expenses	$0.1M	No Change	$0.1M
4	**Total Cost Savings**	**$8.6M**	**$2.5M**	**$10.2M**
5				
6	**SAIDI Reduction**	**15 minutes**	**5.8 minutes**	**20.8 minutes**

Q. Please explain the adjustments in the "Service Restoration Cost Reduction" category.

A. The initial estimate assumed a two-hour improvement in restoration time for both gray sky and catastrophic conditions. However, after reviewing historical data from 2022–2023, and analyzing realized benefits in the historical test year 2024, future projections have been refined to reflect a two-hour improvement for gray sky conditions and a 24-hour improvement for catastrophic conditions.

These adjustments are driven by increased use of technology, and additional operational efficiencies that have been identified, enabling faster and more effective power restoration. Key factors contributing to these efficiencies include clearer role alignment,

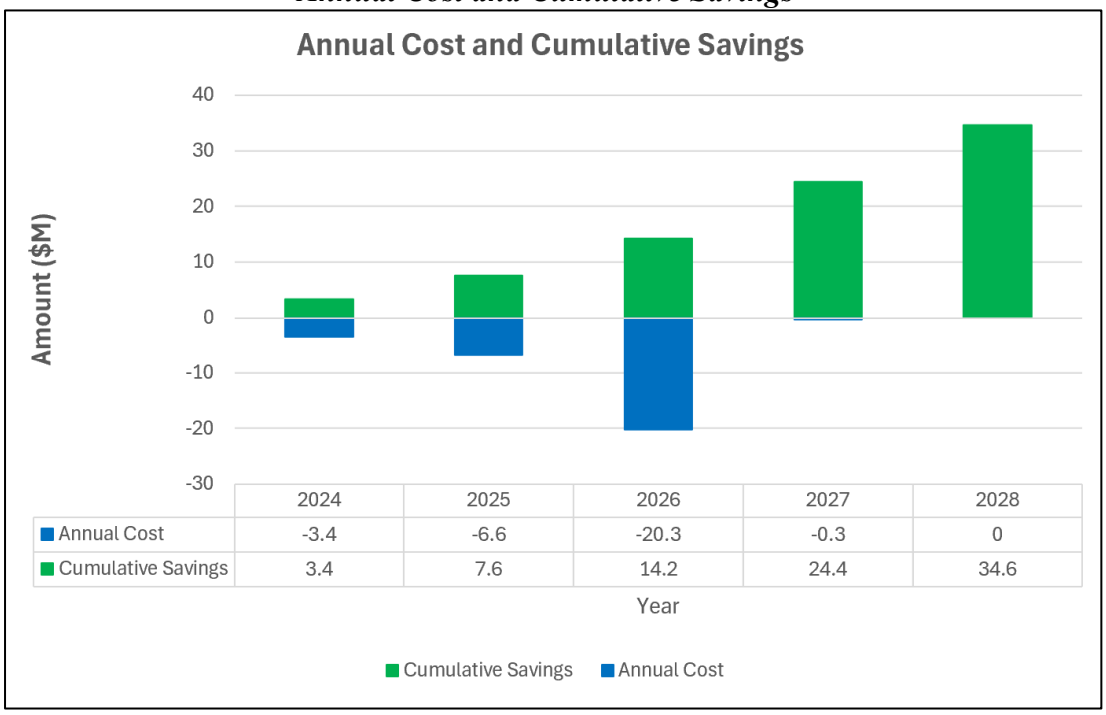
reduced operational hand-offs, co-locating operating groups within the same control center, enhanced training for Grid Operators, and improved system-wide situational awareness.

Q. What are the projected costs associated with this project?

A. The Company projects a total expenditure of $30.7 million for this project, including $15.8 million in the test year ($15.5 million in capital and $308,000 in O&M). These costs support the completion of construction, commissioning, and occupancy of the operating control centers by early 2027, as well as the integration of support group operations within the consolidated control centers.

The capital costs for this project are detailed in Company witness Quentin A. Guinn's Exhibit A-102 (QAG-3), page 1, lines 25 and 26, along with the associated testimony. The O&M costs are provided in Company witness Kelly's Exhibit A-128 (MPK-18), line 27, and the corresponding testimony. Figure 9 illustrates the annual costs, and cumulative savings for the project.

Figure 9
Control/Dispatch Center Consolidation Project Financial Overview: Annual Cost and Cumulative Savings



The costs and benefits figures for this consolidation project represent a shift from testimony provided in previous rate cases as explained earlier in my testimony.

Q. During the historical year, how much was spent on the Control/Dispatch Center Consolidation project?

A. From January 2024 through December 2024, the Company incurred $3.4 million in costs for the Control/Dispatch Center Consolidation project. These expenditures covered design services, material acquisition, and initial space renovations.

Q. Please summarize the Company's proposal for Control/Dispatch Center consolidation and its benefits for customers.

A. The Company's proposal involves consolidating the System Control, Distribution Control, and Dispatch Centers into two fully staffed control centers—one in Jackson and one in

Grand Rapids. Each center will serve as a back-up for the other, with associated process and organizational changes delivering significant customer benefits.

Key Benefits:

- Annual Cost Savings:
  - Service restoration annual cost reduction: $10.1 million.
  - Facilities/IT/Training expense annual savings: $0.1 million.
  - Total annual savings: $10.2 million.
  - A one-time Grid operating labor savings: $0.9 million.
- Outage Response Benefit:
  - All-weather SAIDI reduction: 20.8 minutes per customer.
- Project Cost and Implementation:
  - Total cost: $30.7 million ($15.8 million in the test year).
  - Completion timeline: Construction, commissioning, and occupancy of the two fully staffed control centers by early 2027, including the integration of support group operations.
- Initial Impact:
  - 2024 results: $3.383 million in cost savings and a 4.1-minute SAIDI reduction per customer due to process, organizational, labor reduction, and employee skilling improvements.
  - Full benefit realization projected by March 2028.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

ANDREW R. SNIDER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Andrew R. Snider, and my business address is 4000 Clay Avenue, Grand Rapids, MI 49548.

Q. Are you the same Andrew R. Snider that offered direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to Service Restoration issues raised in the direct testimonies of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Jessica Duell and Theresa McMillan-Sepkoski, Attorney General ("AG") witness Sebastian Coppola, and Citizens Utility Board of Michigan ("CUB") witness Richard J. Bunch.

Q. How is your rebuttal testimony organized?

A. My rebuttal testimony is organized as follows:

I. Test Year O&M
II. Resiliency Fund
III. ESA
IV. Wire Down Process
V. Control/Dispatch Center Consolidation

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

I. Test Year O&M

Q. Please describe AG witness Coppola's proposal for the Service Restoration test year Operating and Maintenance ("O&M").

A. AG witness Coppola proposes a disallowance of $20.6 million for Service Restoration test year O&M because Consumers Energy Company's ("Consumers Energy" or the "Company") requested methodology veers from the practice of using a five-year average of restoration expenses to set the test year amount.

Q. Did any other witnesses in this case object to the Company's Service Restoration test year O&M request?

A. No. In fact, Staff witness Duell states on page 17, lines 24 through 27, of her direct testimony, that she approves of the Company's projected test year expense.

Q. Why is the Company proposing a change in the way service restoration costs are baselined?

A. As mentioned on page 21, lines 3 and 4, of my direct testimony, the historical process was insufficient resulting in a $351 million gap in funding over the past five years. Additionally, the historical method, using a five-year average, was challenged by The Liberty Consulting Group ("Liberty") in their independent audit.

Q. How did Liberty characterize the five-year historical average for calculating the Service Restoration test year O&M request?

A. As I detailed on page 17, lines 27 through 29, of my direct testimony, Liberty stated that, "It is not clear how a five-year average serves as a sound basis for setting budgets or a meaningful marker for sharing restoration costs that vary from five-year averages," and stated that reliance on the five-year average to fund service restoration should end.

Q. Did the Company's Service Restoration test year O&M request consider Liberty's recommendation from the Final Report in Case No. U-21305?

A. Yes. As I detailed on page 18, lines 7 through 17, the Company has stopped relying on a five-year historical average and bases the proposed bridge period and test year O&M amounts on the 2024 historic year expenses. The Company believes this approach provides the most accurate benchmark based on projected service restoration performance requirements. And, as explained below, when the Company's proposed approach to projecting its service restoration expense is paired with the proposed Service Restoration Resiliency Fund ("Resiliency Fund"), it alleviates the AG's concern that the Company's proposed approach does not "even out peaks and valleys in the annual expense."

II. Resiliency Fund

Q. Please describe Staff witness Duell's proposal for the Resiliency Fund.

A. Beginning on page 18, Staff witness Duell objects to approving the Company's proposed Resiliency Fund for several reasons including Staff's support of the full-service restoration expense for the test year, skepticism that customers will see a benefit from this proposal, and a preference to direct underspent Service Restoration expenses into other distribution programs.

Q. Do any other witnesses similarly object?

A. Yes. On pages 53 through 58 of his direct testimony, CUB witness Bunch recommends that the Commission reject the Resiliency Fund because, in his opinion, the proposal is like previously rejected proposals and is unlikely to benefit customers. On page 165 of his direct testimony, AG witness Coppola also recommends that the Commission reject the Resiliency Fund because it, along with the Extraordinary Storm Accounting ("ESA") proposal, are complex and require further study.

Q. Does the Company agree with these witnesses' recommendations for the Resiliency Fund?

A. No. The Company disagrees with the characterization that customers will not benefit from this proposal, as there is no extra cost to customers to implement the Resiliency Fund. Since the fund will either supplement existing service restoration resources or be refunded to customers, there is only customer benefit and upside from this proposal. Furthermore, the Resiliency Fund is not overly complex or similar to previous Company proposals such as the Service Restoration Cost Sharing Mechanism ("SRCSM"). Simply stated: the Resiliency Fund captures underspent service restoration dollars from prior years and saves them for future use if actual spending exceeds authorized amounts. The Company has also never proposed a mechanism in the style of a Resiliency Fund before. Previous recovery mechanisms dealt primarily with overspends, while the Resiliency Fund deals only with underspend and is clearly different from how the SRCSM would have addressed underspend costs.

Q. Does the Resiliency Fund also help address AG witness Coppola's concern, as described on page 165, lines 1 through 4, of his direct testimony, that the Company's proposed approach to projecting its service restoration expense does not "even out peaks and valleys in the annual expense"?

A. Yes. If the Company experiences a year when its service restoration expense is lower than its projected expense – what AG witness Coppola describes as a "valley" – then the difference would be deposited in the Resiliency Fund and would be available to offset expenses in the following year if it is what AG witness Coppola describes as a "peak" year when service restoration expenses are higher than projected.

III. Extraordinary Storm Accounting

Q. Please describe Staff witness McMillan-Sepkoski's proposal for ESA.

A. On page 8, line 14, through page 9, line 3, of her direct testimony, Staff witness McMillan-Sepkoski objected to approving the proposal citing the effectiveness and timeliness of the current ex-parte case process which the Company utilized following the March/April 2025 storm. Additionally, on page 9, lines 4 through 7, she expressed concern over the lack of a defined cost threshold, viewing the proposal as an open-ended mechanism that could lead to uncertainty in future cost recovery.

Q. Has the Company considered a defined cost threshold for the ESA as suggested by Staff witness McMillan-Sepkoski?

A. Yes. The Company considered a cost threshold when developing this proposal and ultimately decided it was impractical. The Company is committed to safe and efficient restorations no matter what acts of nature it's called to respond to. Consumers Energy will not stop restoration until every last customer is restored.

Q. How can customers be assured that the Company is prudent with extraordinary restorations without a specific cost threshold?

A. As shared in my discovery response U21870-ST-CE-0104, "The Company proposes to provide comprehensive storm data such as a breakdown of capital and O&M unit costs for internal and contractor crews, separated by category and demonstration of how its restoration performance during a given ESA event was conducted in a cost-effective manner." The Company also explained that "recovery of the deferred amounts will be included in any future electric rate case proceedings," which would include a prudency review.

Q. What are the benefits of ESA and how do they relate to Staff witness McMillan-Sepkoski's criticism of ESA?

A. ESA establishes a standardized process completely visible to all interested parties in the rate making process. It's transparent and will mandate consistency for future deferred recovery requests for restoration O&M expenses, unlike an ex-parte filing, which by nature does not have specific guidelines and can be filed at any time. In addition to bringing consistency, the ESA delivers important efficiencies. Creating a reasonable standard defining exactly what qualifies for (restoration) deferred accounting saves the Commission, and interested parties, significant time by establishing a rate case process that avoids the need for a separate ex-parte filing.

Q. Do any other witnesses similarly object?

A. Yes. Both CUB witness Bunch and AG witness Coppola appeared to conflate their criticism for the Resiliency Fund with ESA and recommended the Commission reject both proposals. On page 55 of his direct testimony, CUB witness Bunch opines that the ESA will be used frequently and shifts the risk to customers for the cost of restoration from damaging storms.

Q. On page 55, line 5, of his direct testimony, CUB witness Bunch characterizes ESA as not significantly different from past proposals. Does the Company agree?

A. No. CUB witness Bunch inaccurately asserts that ESA is similar to the SRCSM while glossing over key details and distinctions of the proposal. I cover the distinction between ESA and the SRCSM on page 32, lines 1 through 15, of my direct testimony. In the past, the Company has not differentiated extraordinary storms from other catastrophic categories of storms. ESA is therefore far more targeted than past proposals.

The context is different, as well. This case is the first electric rate case filed after the Commission issued its order in Case No. U-21305, which called for a change to service restoration budgeting and specifically endorsed deferral accounting as an effective means for permitting recovery of excess storm costs as I note in my direct testimony on page 18, line 27, through page 19, lines 1 through 3. Deferred accounting was specifically cited as an opportunity in Liberty's independent audit. This is also detailed in my direct testimony beginning on page 29, line 12.

Q. Does the Company agree with CUB witness Bunch's assertion on page 56, lines 12 through 14, of his direct testimony that ESA increases customers' exposure to restoration costs associated with large, extreme weather-related events?

A. No. Whether the Company is granted deferred accounting for extraordinary storm restoration costs through ESA or whether it obtains deferred accounting through an ex-parte proceeding, both approaches allow the Company to recover its reasonable restoration costs for extraordinary storms after a prudency review. Customer exposure remains equal whether the Company files in rates cases or separate cases.

Q. Does the Company agree with CUB witness Bunch's statement that by presenting two distinct mechanisms the Company has repackaged their approach from previous cases?

A. No, the Resiliency Fund and ESA are not interdependent. As I discussed on page 31, lines 10 through 13, of my direct testimony, the two proposals can function independently of one another. The Company has filed for approval of both proposals because they do operate best in tandem, but they can be approved separately.

Q. Does the Company agree with AG witness Coppola's statement on page 166, lines 11 through 14, of his direct testimony suggesting the Commission open a new docket to review the Resiliency Fund and ESA?

A. No. While the Company appreciates AG's willingness to discuss these proposals further, they are rate proposals that deserve to be reviewed, debated, and approved in rate cases. There is no more appropriate opportunity to debate these proposals.

IV. Wire Down

Q. Does the Company Agree with Staff witness Duell's recommendation to change the caution tape used for downed wires?

A. Yes. As referenced in discovery response U21870-ST-CE-0109, 16b, in Exhibit S-18, page 5, the Company historically uses caution tape specifying, "Caution Do Not Enter." The Company's policy for wire guards is to remain onsite until a downed wire is made safe. Therefore, once a location is barricaded with caution tape, a representative should be standing guard until the source is verified de-energized. However, the Company appreciates and will adopt the recommendation to utilize caution tape that indicates the potential of a live wire.

V. Control/Dispatch Center Consolidation

Q. Please describe AG witness Coppola's position on the Control/Dispatch Center consolidation project.

A. AG witness Coppola expresses concern regarding the Company's revised proposal to establish two fully staffed Control/Dispatch Centers. AG witness Coppola questions the justification for the increased capital investment, which has grown from the original $17.2 million to $30.7 million. He asserts that the operational benefits of the dual-center

model are not clearly demonstrated and that the projected cost savings—estimated by the Company at $10.2 million annually—are speculative in nature. AG witness Coppola refers to these savings as "purported" or "potential," suggesting they lack sufficient evidentiary support. Additionally, he characterizes the revised proposal as a "180-degree turn" from the Company's prior plan, which involved consolidating operations into a single facility. He implies that the dual-center approach may be redundant and questions whether the added investment delivers proportional value to customers.

Q. Does the Company agree with AG witness Coppola's characterization of the revised proposal as a "180-degree turn"?

A. No. AG witness Coppola's characterization oversimplifies the evolution of the Control/Dispatch Center initiative. The original plan, as discussed in Case Nos. U-21389 and U-21585, involved logistical consolidation, closing one facility and absorbing its workload into another. The current proposal represents a strategic transformation, including:

- Integration of System Control, Distribution Control, and Dispatch functions,
- Creation of new job classifications across the electric grid, and
- Workforce training and role alignment to support a modernized, resilient operations model.

These phases differ significantly in scope and purpose and should not be directly compared.

Q. Is staffing both Control/Dispatch Centers necessary?

A. Yes. Full staffing at both centers is essential for operational resilience and risk mitigation. In recent years the Company has had to stand down operations at the Jackson location multiple times due to tornado warnings or other weather-related threats, during which control was automatically transferred to Grand Rapids. This operational experience further

validated the need for geographically redundant, fully staffed centers. A second, fully staffed facility ensures continuity of operations and avoids delays in restoration. Additionally, the dual-center model:

- Reduces the risk of losing experienced employees by avoiding forced relocations,
- Supports recruitment and retention in key service areas, particularly Grand Rapids, and
- Aligns with industry best practices for geographic redundancy in critical infrastructure.

Q. Are the projected $10.2 million in annual savings based on actual cost reductions?

A. No. The Company has described these benefits as cost avoidance, which is a valid and recognized planning metric in utility operations. These avoided costs include:

- Reduced service restoration expenses,
- Lower overtime and Incident Command System ("ICS") activation costs, and
- Efficiency gains from improved coordination and situational awareness.

These benefits are detailed in my direct testimony (pages 41–46) and summarized on Figure 8.

Q. Is the revised Control/Dispatch Center plan proposal a reversal of its prior strategy?

A. No. The revised proposal is a strategic advancement informed by lessons learned and employee feedback. The dual-center model is designed to optimize system operations, enhance reliability, and protect workforce stability, while delivering measurable cost avoidance and reliability improvements.

Q. Should the Commission approve the proposed capital expenditures for the Control/Dispatch Center consolidation?

A. Yes. The Company respectfully recommends approval of the proposed investments, recognizing their long-term value to customers and grid operations.

Q. What is Staff witness Duell's general position on the Control/Dispatch Center consolidation project?

A. On page 18, line 26, through page 20, line 18, of her direct testimony, Staff witness Duell does not support full recovery of the capital expenditures requested by the Company for the Control/Dispatch Center consolidation project. Staff witness Duell recommends disallowing 50% of the requested capital for both the bridge period and the projected test year. Based on the Company's historical underspending, Staff witness Duell determined that the variance justifies a proportional reduction in the current funding requests. Additionally, Staff witness Duell questions whether the proposed investments are necessary and whether the operational benefits of the dual-center model are sufficiently demonstrated to warrant approval of the requested capital expenditures.

Q. Does Staff witness Duell support the Company's requested $4.871 million in capital expenditures for the Control/Dispatch Center during the bridge period (the four months ending April 30, 2026)?

A. No. On page 19, line 20, through page 20, line 4, of her direct testimony, Staff witness Duell recommends a disallowance of $2.4 million, representing 50% of the requested bridge period amount. This recommendation is based on the Company's prior performance, where actual 2024 spending was less than projected. Given the variance, Staff witness Duell determined that a proportional adjustment is appropriate.

Q. Is it reasonable to disallow funding for the Consolidated Control/Dispatch Center predicated on historical spend rates?

A. No, it is not. Staff's recommendation to disallow half of the Company's requested $4.871 million in bridge period capital expenditures is based solely on a comparison of projected versus actual 2024 spend. This overlooks the strategic evolution of the project and the timing of expenditures.

The Company's decision to transition from a single Unified Control Center to a dual-location model—Jackson and Grand Rapids—was made during execution to enhance resiliency and retain talent. As I stated in my direct testimony, this change did not cause any rework or redo of prior work. All previously completed engineering, design, and implementation activities remained valid and applicable. The transition was managed without duplicative effort or additional cost.

The lower-than-projected 2024 spend reflects the Company's decision to prolong the design phase to incorporate the expanded scope. The bridge period expenditures represent the natural ramp-up of capital investment following that design work.

Disallowing funding based on historical spend rates ignores the reality that capital projects—especially those involving complex operational infrastructure—do not follow linear spending patterns. The Company's bridge period capital request is reasonable, prudent, and aligned with the revised scope and timeline.

Q. On page 20, lines 10 through 18, Staff witness Duell recommends disallowing half of the Company's proposed $15.497 million capital expenditures for the Control/Dispatch Center consolidation project in the test year. Is the $15.497 million requested for the Control/Dispatch Center in the projected test year justified?

A. Yes. The funding supports the build-out of the dual Control/Dispatch Center model, which includes facilities in Jackson and Grand Rapids. This strategic investment enhances system resiliency, provides geographic redundancy, and ensures business continuity. The revised scope builds upon existing infrastructure in Jackson, preserving prior investments while expanding capabilities. The dual-center model aligns with industry best practices and supports further integration with advanced grid technologies such as Advanced Distribution Management System ("ADMS") and Distributed Energy Resource Management Solution ("DERMS"). These justifications are outlined in my direct testimony at pages 44 through 46.

Q. On page 19, line 20, through page 20, line 4, Staff witness Duell compares the Company's projected 2024 capital spending for the Control/Dispatch Center from Case No. U-21585 with its actual spending on the project in 2024. Does the Company's actual spend below the prior projection indicate overestimation or inefficiency?

A. No. The prior projected spend in Case No. U-21585 was not approved, and the Company should not be held to the amounts it had planned to spend that were not approved. The spending that did occur was prudent and targeted, as shown in Figure 9 on page 45 of my direct testimony and page 40, lines 8 through 28, of my direct testimony. The Company has executed the project in a way that reflects its commitment to fiscal discipline and

regulatory compliance. Using the difference between projected and actual spend as a rationale to deny future funding does not account for the Company's responsible approach to capital planning.

Q. Should the Commission approve the proposed expenditures for the bridge period and projected test year?

A. Yes. The Company maintains that both funding requests are prudent, necessary, and aligned with strategic operational goals. It is very difficult for the Company to complete a project that is only "half supported." These investments support reliability, resiliency, and best practices. The Company is respectfully seeking full support from the Commission to approve the proposed expenditures and recognize the long-term value of the Control/Dispatch Center transformation for our customers.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Thank you.

Next is company witness Sara E Stewart. Ms. Stewart had revised direct testimony consisting of a cover page and 51 pages of questions and answers she also had rebuttal testimony consisting of a cover page and nine pages of questions and answers Ms. Stewart also sponsored revised Exhibit A-170, Exhibits A-171, A-172, and A-173, confidential Exhibit A-174, and exhibits A-175, A-176, and A-177.

THE COURT: Are there any objections to the admission of this testimony or are these exhibits?

Hearing none. The direct revised and rebuttal testimony of Sara Stewart is bound in the record and Exhibits A-170 revised, A-171 through A-173, A-175, and A-177 are admitted into the public record, and Exhibit A-174 is admitted to the confidential record.

(At 3:07 p.m., Exhibits A-170 revised, A-171 through A-173, A-175, and A-177 are admitted into the public record, and Exhibit A-174 is admitted to the confidential record)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REVISED DIRECT TESTIMONY

OF

SARA E. STEWART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Sara E. Stewart and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

QUALIFICATIONS

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Senior Manager of Forestry Operations.

Q. Please describe your educational background and work experience.

A. I have 11 years of utility experience at Consumers Energy within the Forestry Department with extensive experience in the development and execution of the Line Clearing Program. Over these years, I have held roles and performed the duties of all field and leadership positions within the Forestry team overseeing strategy and operations, as well as driven continuous improvement and technology enhancements including the development of the forestry model and workplan selection tool. I am skilled in distribution, service restoration, contract management, as well as financial management. I hold a Bachelor of Science degree in Natural Resources and Environment from the University of Michigan with a concentration on Resource Ecology and Management. I am an International Society of Arboriculture Certified Arborist and Certified Utility Specialist. I also hold a Michigan Department of Agriculture and Rural Development Pesticide Applicator Certification.

Q. What are your responsibilities as Senior Manager of Forestry Operations?

A. I have responsibilities for all forestry functions including line clearing, budgeting, planning, and operations for the Company's distribution system.

Q. Have you ever been a witness in a Michigan Public Service Commission ("MPSC" or the "Commission") case?

A. No, but I have supported Pamela L. Bolden and Chris A. Shellberg as they prepared testimony and exhibits in the last several rate cases: Case Nos. U-21585, U-21389, U-21224, U-20963, and U-20697. Besides this, I participated in the distribution audit in Case No. U-21305 by preparing responses to the Liberty Consulting Group's ("Liberty") written audit requests and being interviewed and have had oversight of the Company's Line Clearing Program Annual Report and Line Clearing Program Formal Optimization Analysis of Line Clearing Cycles in Case No. U-20697.

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's request in this case for an increase in funding for its Line Clearing Program. My direct testimony is presented in six sections: 1) Description of the Line Clearing Program; 2) Recent Progress of the Line Clearing Program; 3) Vision for the Line Clearing Program; 4) Reliability Benefits of the Line Clearing Program; 5) Expense Requirements for the Line Clearing Program Vision; and 6) Resourcing Plan for the Line Clearing Program Vision.

EXHIBITS

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-170 (SES-1)	Line Clearing O&M Expense;
Exhibit A-171 (SES-2)	Projected LVD Tree-Caused Reliability Impacts of the Line Clearing Ramp-Up Plan;
Exhibit A-172 (SES-3)	2025 HVD Line Clearing Work Plan;

Exhibit A-173 (SES-4)	2025 LVD Line Clearing Work Plan;
Confidential Exhibit A-174 (SES-5)	Post-Work Review Supporting Documentation Examples;
Exhibit A-175 (SES-6)	Summary of O&M Expenses Projected Using Inflation;
Exhibit A-176 (SES-7)	Formal Optimization Analysis of Line Clearing Cycles; and
Exhibit A-177 (SES-8)	Utility Vegetation Management in North America: Results from a 2019 Utility Forestry Census of Tree Activities and Operations.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

DESCRIPTION OF THE LINE CLEARING PROGRAM

Q. Please explain the Company's Line Clearing Program.

A. The Company's Line Clearing Program is responsible for maintaining clearance between vegetation and energized equipment and to eliminate vegetation hindering accessibility to the Company's electric lines. The Company uses Integrated Vegetation Management ("IVM") along the Company's electric line rights-of-way to accomplish these objectives. IVM is the practice of promoting compatible plant communities along rights-of-way using a combination of cost-effective methods, including chemical, cultural, mechanical, or manual treatments. This work is performed by contractors with qualified line clearance tree trimmer employees, in accordance with Michigan Occupational Safety and Health Administration (MIOSHA) requirements, on production-oriented contracts with the Company. The Line Clearing Program is divided into two parts: (i) High Voltage Distribution ("HVD") Line Clearing; and (ii) Low Voltage Distribution ("LVD") Line Clearing.

Q. Please describe HVD Line Clearing.

A. HVD Line Clearing manages vegetation along the Company's high voltage systems. There are two major voltages on the Company's HVD system: 46 kilovolts ("kV") and 138 kV. The Company clears vegetation within an 80- to 120-foot-wide right-of-way for these voltages to attain a minimum of 15 feet of separation for 46 kV lines and 20 feet of separation for 138 kV lines between conductors and vegetation at the time of clearing. The Company also manages vegetation within the right-of-way to maintain accessibility along the right-of-way for maintenance and repair of the line. During scheduled maintenance line clearing, the Company identifies and removes hazard trees up to 40 feet from the edge of the right-of-way. HVD Line Clearing is divided into multiple subprograms.

Q. Please explain what projects, activities, and other types of work will be funded by spending in HVD Line Clearing.

A. HVD Line Clearing consists of an IVM program that promotes reliability by reducing tree-caused outages and decreasing the impact of storms. HVD Line Clearing consists of four subprograms: (i) maintenance clearing; (ii) brushing and herbicide treatment; (iii) demand clearing; and (iv) noxious weed control (grass and weed mowing to meet local ordinances). HVD Line Clearing also includes Forestry Operations Administration expenditures.

The IVM program provides reliability benefit to customers while maintaining and promoting a healthy ecosystem along the Company's HVD rights-of-way. The Company's HVD and LVD rights-of-way are enrolled in the U.S. Fish and Wildlife Service's Conservation and Consent Agreement with Assurances ("CCAA") for the monarch

butterfly. The CCAA also requires protection for other pollinator species as well as threatened and endangered species that are found in these areas.

Q. What is HVD maintenance clearing?

A. The Company's HVD maintenance clearing work consists of scheduled cycle maintenance activity for trimming and removing trees within the right-of-way corridor and includes hazard tree removal outside of the right-of-way. HVD rights-of-way are typically cleared 40 feet on either side of the centerline to remove all tree species and shrubs that inhibit right-of-way access. Specimen trees growing along city streets or landscaped residential properties may be trimmed to attain a minimum of 15 to 20 feet of clearance instead of removal. A tree outside of the right-of-way is considered a hazard tree if it is tall enough to strike the HVD line if it fell and if it is dead, diseased, infected with destructive insects, or structurally weakened.

Q. What is HVD brushing and herbicide treatment?

A. The Company conducts brush cutting and herbicide treatment in HVD rights-of-way to reduce the volume of small trees growing within the right-of-way before they grow to a height that may interfere with the line. This work also allows line worker crews to access equipment for repair or replacement. Brush control work: (i) is completed on a four-year cycle schedule; (ii) reduces future stem volume; (iii) promotes the growth of compatible species within the right-of-way; and (iv) supports or maintains habitat needed for several endangered, threatened, or rare species of plants and animals.

Q. What is HVD demand clearing?

A. HVD demand clearing work addresses emergent vegetation threats to the Company's HVD system. These threats are identified by HVD vegetation inspections and by helicopter

patrols of the HVD system. Demand clearing work most often involves partially uprooted trees that are leaning towards the line that will eventually fall onto the line. These situations require immediate remediation to prevent an outage.

Q. What is HVD noxious weed control?

A. The Company's noxious weed control work maintains compliance with local ordinances for maintaining vegetation on fee-owned HVD rights-of-way in predominantly urban areas. These ordinances do not permit vegetation growth above a specified height, requiring three to six mowing cycles of affected rights-of-way each year, with variation due to rainfall and temperature.

Q. Please describe LVD Line Clearing.

A. LVD Line Clearing manages vegetation along LVD primary voltage systems and secondary voltage systems, including service conductors. The Company clears vegetation within a 30-foot-wide right-of-way for primary voltages to attain a minimum of 10 feet of separation between conductors and vegetation at the time of clearing and to maintain accessibility along the right-of-way for maintenance and repair of the line. As a part of LVD line clearing, hazard trees, such as dead or dying trees that are within 20 feet of the edge of the right-of-way that are accessible to aerial lift trucks, are removed when not objected to by the property owner. LVD Line Clearing is divided into multiple subprograms.

Q. Please explain what projects, activities, and other types of work will be funded by spending in LVD Line Clearing.

A. LVD Line Clearing consists of seven subprograms: (i) program maintenance (full circuit clearing); (ii) repetitive outage zonal clearing; (iii) Customers Experiencing Multiple

Interruptions ("CEMI") clearing; (iv) first zone clearing; (v) Load Concentration Point ("LCP") zonal clearing; (vi) demand clearing (customer requested work); and (vii) brush control. LVD Line Clearing also includes Forestry Operations Administration expenditures.

Q. What is LVD program maintenance (full circuit clearing)?

A. LVD program maintenance clearing is the predominant, scheduled maintenance clearing work for the LVD system. Trees are cleared to attain at least 10 feet of clearance to LVD primary conductors. Secondary voltage conductors and services are cleared of any tree limbs displacing or rubbing on these conductors. Brush (sapling trees and woody shrub species) is cut within the 30-foot right-of-way. Hazard trees (dead, dying, or mechanically stressed trees) within 20 feet of the edge of the right-of-way are removed when not objected to by the property owner.

Q. What is LVD repetitive outage zonal clearing?

A. LVD repetitive outage zonal clearing targets specific sections of circuits that are experiencing high levels of tree-caused outages. Monthly, the Company reviews sections of circuits for multiple tree-related, non-Major Event Day ("MED") outages within the previous 12 months. Identified sections are scheduled for clearing based on system reliability impacts and resource limitations. These sections are cleared to the same specifications as program maintenance work.

Q. What is LVD CEMI clearing?

A. LVD CEMI clearing is designed to target customers experiencing high numbers of outages during the current calendar year and reduce the likelihood that these customers will experience similar outages going forward. CEMI clearing differs from repetitive outage

clearing as CEMI is focused on the cumulative effect of all upstream LCPs from the customer's location, whereas repetitive outage is focused on the number of outage incidents in a particular LCP. For CEMI, no particular LCP may be experiencing outage rates at the repetitive outage level, but the cumulative effect of multiple upstream devices, each with just a few outages, results in the customer having many outages. CEMI clearing targets selected areas upstream of the customer location to reduce future tree-caused outages. CEMI areas may be cleared to the same specifications as program maintenance or select individual trees may be targeted for clearing depending on the vegetation conditions of the CEMI-identified section and the length of the section to be cleared.

Q. What is LVD first zone clearing?

A. LVD first zone clearing targets the section of a circuit from the substation outward to logical LCPs. Typically, these are three phase structures (poles with X, Y, and Z phasing) and any unfused laterals extending from this first zone. Although these zones may have lower outage frequency than other areas, outages that do occur impact a higher number of customers. This work reduces the likelihood of full circuit lockouts due to trees and provides a reliability benefit for all customers connected to the circuit. First zones are selected based on the previous 12-month tree-related outage history each fall when work plans are developed for the upcoming year. Clearing of first zones is targeted for first and second quarters of the work plan year to maximize the reliability benefit to all customers of the circuit. First zones are currently cleared to the same specifications as program maintenance with the exception that individual trees with overhanging branches regardless of clearance above conductors have been considered for 100% removal of these overhanging branches.

Q. What is LVD LCP zonal clearing?

A. To comply with the Settlement Agreement for MPSC Case No. U-21224, the Company incorporated LVD LCP zonal clearing as a new subprogram starting in 2024 that targets the worst performing zones across the LVD system. In the 2024 calendar year, the Company cleared 42 miles under the LCP zonal clearing subprogram. These sections are cleared to the same specifications as program maintenance work. This subprogram differs from the repetitive outage subprogram in that LCP zonal clearing work is evaluated and added to the annual work plan at the beginning of the calendar year, whereas repetitive outage work is evaluated monthly.

Q. What is LVD demand clearing?

A. LVD demand clearing addresses emergent vegetation threats to the LVD system. Emergent vegetation threats are identified predominantly by customers calling in personal observations around their homes, from forestry operations personnel, and from other electric operations employees performing duties in the field. The Company's forestry operations personnel review these requests in person, or through phone conversations, with the reporting party to validate the emergent nature and the likelihood of an outage. Work that can wait until maintenance clearing will be performed is delayed, but validated threats to the system are prioritized and addressed based on potential system reliability impacts and resource limitations.

Q. What is LVD brush control?

A. LVD brush control uses herbicide applications to treat brush within the LVD right-of-way two to three years following full circuit clearing, particularly on rural and suburban circuits with higher brush densities in the right-of-way. This work reduces future stem volume,

promotes the growth of compatible species within the right-of-way, and helps maintain accessibility for line maintenance or repair. Brush growing in or near wetlands or open water bodies is manually or mechanically cut instead of being treated with herbicides.

Q. What standards apply for trimming trees along service lines?

A. Customer service lines are cleared of trees or parts of trees that are displacing or rubbing on these conductors. Service line clearing is identified and occurs during program maintenance (full circuit clearing) and other scheduled Operating and Maintenance ("O&M") subprograms. The Company also addresses tree issues along service lines outside of scheduled O&M subprogram clearing on an emergent basis through its demand subprogram by removing trees or parts of trees that have fallen on service lines and trimming limbs that are causing damage to conductors.

Q. Does the Company perform quality assurance of line clearing work done in the field by contractors?

A. Yes. In accordance with Rule 505 of the Commission's Technical Standards for Electric Service, Mich Admin Code, R 460.3505, as amended through MPSC Case No. U-20630, the Company performs quality assurance of line clearing work through its standard post-work review process for scheduled O&M projects. After planned line clearing work is completed, the contractor submits a Circuit Closing Form for each section of circuit. A statistically relevant representative inspection is then completed where the Company reviews the work in the field to ensure clearance is obtained and hazard trees are removed as planned. If trees, brush, or vines were missed by the line clearing contractor, tree crews are sent back to complete the work on non-billable time. Upon completion of this re-work, the contractor submits a Weekly Summary Crew Report identifying when, by whom, and

with what equipment the non-billable work was completed. Confidential Exhibit A-174 (SES-5) contains documentation supporting this process. As an example, for scheduled O&M work, the Company required 720 hours of non-billable labor in 2024 identified through its post-work review process. It is important to note that the Company has internal forestry operations personnel presence in the field as work is being completed by line clearing contractors, which results in quality assurance checks and corrections throughout work completion. It is in the best interest of the Company, its electric customers, and its line clearing contractors to prevent defects and increase first-time quality of work, thus driving down the number of defects discovered in post-work review and resulting non-billable labor hours.

Q. Does the Company's Line Clearing Program include clearing required for service restoration?

A. Forestry is a key piece of the Company's service restoration efforts. Forestry manages the tree crews during restoration events, working together with many other areas of the Company to restore service or address emergent threats to the system. The costs for this work are captured in service restoration expenses. Service restoration expenses are addressed by Company witness Andrew R. Snider and are not a part of the line clearing funding discussed in my direct testimony. However, the funding requested for line clearing establishes a base of tree crews working on the system that are utilized for service restoration work when needed.

RECENT PROGRESS OF THE LINE CLEARING PROGRAM

Q. Please describe the Company's recent progress for its HVD Line Clearing subprogram.

A. The Company has continued to maintain a four-year clearing cycle for its HVD system. Figure 1 below shows five-year actual clearing and expenditure data and a summarization of the most recent four years of clearing towards the cycle.

FIGURE 1
HVD LINE CLEARING HISTORICAL CLEARING AND EXPENDITURES

Description	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	4-Year Cycle 2021-2024
Cleared Miles	1,116	1,178	1,106	1,153	1,203	4,640
Planned Miles	1,103	1,129	1,161	1,164	1,166	4,620
O&M Expense ($M)	$9.17	$10.74	$10.99	$11.30	$10.73	$43.76
Planned O&M Expense ($M)	$9.48	$12.60	$11.71	$12.06	$12.28	$48.65
$/line mile	$8,219	$9,117	$9,932	$9,801	$8,919	$9,431
Clearing Cycle (years)	4.2	4.2	4.2	4.2	4.0	4.0

Q. Please list any prioritized projects for maintenance clearing work in the HVD line clearing subprogram for 2025.

A. In 2025, the Company is planning HVD line clearing on the lines listed in Exhibit A-172 (SES-3).

Q. Please describe the Company's recent progress for its LVD Line Clearing subprogram.

A. The Company has been working towards attaining a seven-year effective clearing cycle for its LVD system and has not yet attained this cycle. Figure 2 below shows five-year actual clearing miles, expenditure data, workplan backlog and cycle percentages, and a

summarization of the most recent five years of clearing towards the seven-year effective cycle target.

FIGURE 2
LVD LINE CLEARING HISTORICAL CLEARING AND EXPENDITURES

Description	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	5-Year Actual 2020-2024
O&M Cleared Miles	4,211	5,279	6,388	6,365	6,030	28,273
O&M Planned Miles	3,166	5,223	5,636	5,875	6,760	26,660
O&M Expense ($M)	$46.10	$75.83	$91.02	$97.79	$99.49	$410.23
Planned O&M Expense ($M)	$41.36	$71.43	$81.49	$87.97	$105.37	$387.62
$/line mile	$10,948	$14,364	$14,248	$15,364	$16,499	$14,510
Effective Clearing Cycle (years)	13.1	10.6	9.1	9.3 ~~2~~	9.7	10.2 ~~1~~
Workplan Backlog Miles Percentage	98%	87%	67%	82%	80%	82%
Workplan Cycle Miles Percentage	2%	13%	33%	18%	20%	18%

Q. Please list any prioritized projects for full circuit clearing work in the LVD line clearing subprogram for 2025.

A. Exhibit A-173 (SES-4) shows the 2025 LVD work plan which includes the forestry model output circuits and circuits begun in 2024 with completion carrying over to 2025.

Q. Please describe the seven-year effective cycle and how it works.

A. The seven-year effective cycle describes a strategy of clearing one-seventh of LVD system miles per year with different targeted cycle lengths of clearing for the three major primary voltages on the LVD system. Upon achieving the seven-year effective cycle, 14.4/24.9 kV circuits would be cleared on average between four to six years, 7.2/12.47 kV circuits would be cleared on average between six to eight years, and 4.8/8.32 kV circuits would be cleared on average between eight to ten years depending on the circuits' historical performance, reliability predictions from the forestry model, and safety considerations. The Company first used historic actual data in MPSC Case No. U-20697 to justify that the seven-year

effective cycle was the most cost-beneficial approach to reducing tree-related outages on the LVD system at current system conditions. Figure 3 shows the annual clearing miles schedule required to maintain the seven-year effective cycle for the LVD system once it is achieved.

FIGURE 3
LVD CLEARING SCHEDULE FOR 7-YEAR EFFECTIVE CYCLE

Substation Voltage Class	Approximate System Miles	14% Clearing Program – miles/year cleared	Effective Cycle for Voltage Class
14.4 kV	18,000	3,600	5 years
7.2 kV	10,700	1,529	7 years
4.8 kV	32,300	3,589	9 years

Q. Has the Company made LVD line clearing specification changes in recent years?

A. Yes, the Company has made changes to its line clearing specification in recent years. In 2009, it added enhanced overhang clearance requirements for weak-wooded species overhanging primary wires from 15 feet to 20 feet. In 2016, the Company incorporated hazard tree removal as part of its base LVD primary line clearing specifications.

Q. What recent technology enhancements has the Company utilized in its Line Clearing Program?

A. The Company recently modernized its forestry model by harnessing more sophisticated predictive and prescriptive analytics in Machine Learning and satellite imagery analysis to influence and guide its LVD full circuit clearing subprogram. The forestry model has been built into a web-based tool, called the forestry workplan selection tool, to allow for a consistent, stable, and sustainable methodology to optimize the yearly LVD full circuit clearing workplan to capture the most reliability and safety benefit for annual spend. The output of the forestry model is an input into the forestry workplan selection tool. This new

technology was first utilized to generate the 2023 LVD full circuit clearing workplan and has continued to be used annually. The underlying forestry model that is built into the forestry workplan selection tool is retrained on the most up-to-date data sources annually for an updated risk assessment.

Q. Please explain how the forestry workplan selection tool works and how it functions to reduce tree-caused outages.

A. The forestry workplan selection tool uses the output of the forestry model, which is a Machine Learning model that uses hundreds of data inputs to predict tree-related reliability impacts across the LVD system for the following year. Because an understanding of individual circuit return on investment is necessary to capture the highest reliability benefit for the spend, this selection tool includes the use of satellite imagery analysis to more accurately project costs to clear them. Reliability predictions coupled with historical safety performance (e.g., hazard events including trees on line, wires down, etc.) and cost projections are then fed into an optimization engine with parameters identified (e.g., budget) to automatically generate a targeted LVD full circuit clearing workplan that captures the highest amount of reliability and safety risk.

VISION FOR THE LINE CLEARING PROGRAM

Q. What is the Company's vision for its Line Clearing Program?

A. The Company's vision for its Line Clearing Program is simple: fewer tree-caused outages on its system that will improve electric reliability for its customers in all conditions. To achieve this, the Company is proposing to maintain a four-year clearing cycle for its HVD system and, for its LVD system, proposing a ramp-up to a five-year clearing cycle and performing more aggressive line clearing on targeted three phase primary lines. The

proposed timeline to achieve the shortened line clearing cycle and scope of more aggressive line clearing is targeted by the end of the 2030-2031 test period, which is a similar timeline the Company proposed in MPSC Case No. U-21585 to achieve its previous seven-year effective cycle strategy. Additionally, the Company is proposing an LVD tree-caused outage review program to perform deeper causal analysis of tree-caused outages to provide valuable insights and inform future line clearing strategy decisions.

Q. Please describe the five-year cycle strategy and how it works.

A. The five-year cycle strategy describes clearing one-fifth of the Company's LVD line miles annually in steady-state cycle maintenance while maintaining the standard that all LVD circuits have been fully cleared within a five-year period. The Company's proposal includes a ramp-up strategy to eliminate all backlog miles (circuits that have not been fully cleared within five years) by the end of the 2030-2031 test period. During this ramp-up period, the Company proposes to utilize its forestry workplan selection tool to inform the sequencing of backlog reduction based on its optimization outputs for reliability and safety risk.

After the ramp-up period, steady-state cycle maintenance begins in 2031. At that time, the Company will reevaluate other tactics for continuous improvement in risk management.

Q. Is the Company making changes to its key tracking metrics for LVD line clearing?

A. Yes. As noted, the Company's vision includes bringing all LVD circuits, regardless of voltage class, to a state of having been fully cleared within a five-year period to establish a consistent, full cycle. In its previous rate cases describing the seven-year effective cycle strategy, the Company has tracked progress towards the cycle utilizing a total-miles metric

that encompassed all LVD full circuit clearing miles, LVD subprogram clearing miles, LVD spray miles, and LVD capital clearing miles. This metric was used to summarize the effective cycle for a given year, as shown in Exhibit A-170 (SES-1), line 40. To support its vision, the Company will now track LVD full circuit clearing miles as its main metric towards attaining the five-year cycle line clearing strategy and track other miles (LVD subprogram clearing miles, LVD spray miles, and LVD capital clearing miles) separately and not as part of the standard cycle. This metric is shown in Exhibit A-170 (SES-1), line 23. This ensures the entire LVD system is brought to a consistent state of clearing with no circuits or sections of circuits left in backlog status.

Q. If the LVD system is to be on a five-year cycle by the end of the 2030-2031 test period, what will happen to non-full circuit clearing subprograms?

A. As the LVD system grows nearer to being on a five-year cycle, the necessity of partial circuit clearing subprograms for reliability intervention (repetitive outage zonal clearing, CEMI clearing, first zone clearing, LCP zonal clearing) lessens. Starting in 2026 and through the 2030-2031 test period, the Company will phase out these subprograms for backlog circuits in favor of full circuit clearing for these circuits to bring them on-cycle. After the 2030-2031 test period when the LVD system is projected to be fully on-cycle, the Company will only perform these activities on mid-cycle circuits if the need arises. The Company finds that mid-cycle clearing is a common practice among utilities it conducts benchmarking with.[1]

[1] Specifically, Alliant Energy, Ameren Missouri, American Electric Power perform mid-cycle clearing.

Q. How will the Company address the backlog of circuits not cleared in many years?

A. The Company's proposal to execute a five-year cycle strategy by the end of the 2030-2031 test period is made possible by preventing any on-cycle circuit from exceeding its cycle and becoming a backlog circuit starting this test period. In practice, this means any LVD circuit that reaches five years since it was last fully cleared, therefore reaching its cycle length, is automatically included in the annual workplan for the year to be kept on-cycle. As outlined in Figure 4, remaining miles for the workplan will be backlog miles, addressed throughout the ramp-up strategy timeframe of this test period (Year 1) through the 2030-2031 test period (Year 5).

FIGURE 4
PLAN FOR LVD BACKLOG MILES ELIMINATION
FULL CIRCUIT CLEARING MILES

Vision Year	Plan Miles	On Cycle Miles	Backlog Miles	Backlog Miles Remaining
Year 1	9,019	5,279	3,740	26,684
Year 2	10,885	6,338	4,547	22,138
Year 3	12,814	6,365	6,449	15,689
Year 4	13,588	6,042	7,546	8,143
Year 5	14,837	6,694	8,143	0

Q. Why is the Company deviating from its previous seven-year effective cycle strategy?

A. In its final report, Liberty recommended the Company achieve a four-or-five-year line clearing cycle for LVD circuits by year-end 2028. While the Company has always acknowledged the reliability benefits of shorter cycles (i.e., a reduced cycle results in lower tree-caused outage rates on the LVD system), it has sought to balance reliability benefits with costs to maintain the cycle. In previous rate case analysis, a seven-year effective cycle was outlined as the most cost-beneficial approach for customers. Since that analysis took

place, additional data analysis and information, including Liberty's recommendation and report, has become available for consideration. The Company has carefully evaluated projected costs and benefits of a shorter line clearing cycle for its LVD circuits and has determined that a five-year line clearing cycle is the right approach to significantly improve electric reliability while responsibly managing customer bill impacts.

Q. Why is the Company's vision timeline to achieve the cycle longer than Liberty's recommended timeline?

A. While the Company is proposing a line clearing cycle that aligns with Liberty's recommendation, the aggressive timeline of achieving the shorter cycle by year-end 2028 is not operationally feasible due to rate case timelines and resource acquisition challenges that would result from such a short timeline (e.g., a full ramp-up and execution from mid-2026 through year-end 2028). These resource acquisition challenges could also lead to higher costs if the Company is required to rely on additional out-of-state crews, and these higher costs also caution against a too-aggressive timeline. The Company's proposal to achieve the reduced line clearing cycle reflects an operationally feasible timeline that is just two to three years longer than Liberty's recommendation: by the end of the 2030-2031 test period.

Q. Has the Company performed a formal optimization analysis of line clearing cycles that accounts for customer costs of outages, the costs of service restoration, and the costs of line clearing, including an evaluation of shorter clearing cycles?

A. Yes. To comply with the Order for MPSC Case No. U-21389, the Company filed its formal optimization analysis of line clearing cycles on September 3, 2024, in Case No. U-20697 (the "Analysis"). The Analysis is included in Exhibit A-176 (SES-7).

Q. What was the conclusion of the Analysis?

A. The conclusion of the Analysis was an optimal cycle length between six and seven years, prioritizing and focusing on residential customers. A four-year cycle length was first identified as an optimal cycle when considering combined costs across all customer types (residential and non-residential). The Company took the analysis a step further, considering how line clearing and service restoration costs would be allocated to each customer type. Residential customers bear the majority of the line clearing and service restoration costs through rates as they make up the majority of the electric customers served (about 88% of total). Upon isolating cost impacts on residential customers, and utilizing then-current data, the Company's refined analysis found that a longer cycle length between six and seven years was the optimal point for residential customers minimizing total costs.

Q. Why isn't the Company proposing a cycle length matching the conclusion of the Analysis for residential customers?

A. The Company acknowledges Staff's concerns regarding the approach taken with the Analysis. Among these, Staff comments that the Analysis uses the Interruption Cost Estimate ("ICE") calculator and that these costs are low.[2] While the Company utilized the data from the ICE calculator as it is the best available data of its kind, it acknowledges that a higher residential customer cost of outages would drive the Analysis conclusion towards a shorter optimal cycle for residential customers. The Company is adjusting its proposed line clearing cycle length to accommodate Staff's concern, among other reasons. The shorter cycle length also aligns with Liberty's recommendation, which is influenced by

[2] Michigan Public Service Commission Staff Reply Comments on the Final Report Utility Distribution Audit of Consumers Energy, January 17, 2025, pages 2-3

benchmarking of other utilities, and would result in lower tree-caused outage rates on the LVD system to provide customers with better reliability.

Q. Has the Company analyzed the feasibility of more aggressive line clearing in everything outside of the first zone?

A Yes. To comply with the Order for MPSC Case No. U-21389, the Company has analyzed the feasibility of more aggressive line clearing, defined as canopy removal, in everything outside of the first zone and alternate options in Case No. U-21585.

Q. For the Company's vision, what does more aggressive line clearing entail?

A. More aggressive line clearing describes the practice of canopy removal, which is the removal of all branches above primary wires. In comparison, the Company's general line clearing specification for LVD primary has allowed some canopy to remain: healthy, non-weak-wooded tree species canopy is cleared to 10-15 feet from the conductors, and certain weak-wooded tree species canopy clearance is increased to 20 feet from the conductors. The practice of canopy removal targets all branches above primary wires, regardless of clearance distance, tree species, or health of limb.

Q. Has the Company previously performed canopy removal on its LVD system?

A. Yes. In 2022, the Company performed a small canopy removal study on approximately 42 miles of three phase primary which resulted in an observed average contractor cost increase of 35% per mile cleared. Figures 5 and 6 show examples of canopy removal on an urban and rural section of circuit respectively, pre- and post-clearing in 2022.

FIGURE 5
CANOPY REMOVAL ON AN URBAN SECTION OF CIRCUIT, 2022



FIGURE 6
CANOPY REMOVAL ON A RURAL SECTION OF CIRCUIT, 2022



Q. Where is the Company proposing to remove canopy on its LVD system?

A. The Company is proposing canopy removal on 10% or roughly 5,500 miles of overhead primary, targeting the three phase portions of circuits that have the highest consequence of failure due to serving the most downstream and/or critical customers. Decreasing the risk of tree-caused outages along this targeted three phase primary increases the availability and enablement of manual and automatic switching capabilities, reducing the impact of outages that may occur regardless of cause.

Q. Does this scope of canopy removal match an option presented in Case No. U-21585's feasibility of more aggressive line clearing?

A. No, this proposal does not directly match an option presented in Case No. U-21585, where zones and number of phases were used to differentiate between options. The Company is proposing that zone number alone not be the determining factor for canopy removal, but the consequence of failure of the section of line in question, which will inherently include the first and some second zones, but may extend past the second zone depending on the zone attributes (e.g., number of customers served downstream, and/or if the conductor is within the path of substation-to-substation connection to enable switching opportunities).

Q. Why is the Company proposing to remove canopy on targeted LVD three phase lines?

A. Upon evaluation of the feasibility of more aggressive line clearing on its LVD system, the Company has integrated this tactic into its vision, scoped to the sections of line that are projected to provide the greatest impact to overall customer reliability for the incremental expense. It is not uncommon for electric utilities to have more aggressive clearing specifications in early zones versus later zones; inherently, more customers are served by early zones and by fewer zone miles, which increases overall customer benefit of more

aggressive line clearing in these zones. As outlined in Case No. U-21585, 100% of customers fed by LVD lines are served within and downstream of first zones, which comprise about 6% of total LVD miles.

Q. How will the Company measure the reliability impact of the proposed targeted canopy removal?

A. To measure the reliability impact of the proposed targeted canopy removal, the Company plans to compare the zones that had canopy removal (i.e., "treatment population") to zones or circuits that did not have canopy removal (i.e., "control population"). This comparison is intended to isolate and measure the impact of the treatment (i.e., canopy removal) effect on reliability. The Company is considering including this analysis in Case No. U-20697's Line Clearing Program Annual Report, which details the progress of the line clearing program and the performance of LVD circuits post-clearing. While the Company is proposing to begin executing on its canopy removal strategy in this test period, it is crucial that the data size of the treatment population and amount of time post-treatment are of a significant size to ensure conclusions drawn from an analysis are statistically significant; therefore, measurement of the reliability impact of the proposed targeted canopy removal would appear at the earliest in the 2028 Line Clearing Program Annual Report, analyzing 2027 reliability performance. This will allow the treatment population time to begin collecting reliability data.

Q. Please describe the tree-caused outage review program and how it works.

A. The purpose of the tree-caused outage review program is to gather data on a subset of LVD tree-caused outages and determine top causal contributors, establish and monitor trends, and inform future line clearing strategy decisions. Data collection is to occur by outage

investigators through a combination of: (i) field visits to the site where the tree-related fault occurred; (ii) conversations with field employees that responded to the outage; and (iii) conversations with in-office resources that were involved with the outage (i.e., dispatcher). The Company plans on utilizing contracted resources with a background in forestry and an understanding of tree species and failure modes to perform the outage investigator function.

Q. What tree-caused outages will be targeted for the outage review program?

A. The Company is proposing an outage review trigger upon meeting the following criteria: (i) non-MED; (ii) circuit lockout and/or primary outage; (iii) cause code of Trees or Trees - Outside ROW; and (iv) greater than or equal to 500 customers impacted. For the last five years, there have been about 250 outages on average that meet these criteria annually.

Q. What line clearing tactics are the Company proposing for wildfire mitigation?

A. In Case No. U-21585, the Company proposed to implement a five-year line clearing cycle in elevated wildfire risk areas better to manage growth and limit potential vegetation to conductor contact. The incremental expense for this was outlined in Company witness Michael P. Kelly's Exhibit A-114 (MPK-22) in Case No. U-21585. Because the Company is proposing a shorter five-year cycle for the entirety of its LVD system, the line clearing expense in the elevated wildfire risk areas is now included in the overall Line Clearing Program costs outlined in Exhibit A-170 (SES-1) and are no longer an incremental expense.

While the Company outlines a timeline to achieve the vision by the end of the 2030-2031 test period for all LVD circuits, it is proposing a more aggressive timeline in wildfire

risk areas, namely, achieving the five-year cycle for circuits in the relatively high wildfire risk area by year-end 2026 and relatively moderate wildfire risk area by year-end 2028.

Q. What does the Company have planned for future enhancements to technology?

A. The Company continues to evaluate new forestry workflow management processes and technology enhancements. The Company's Forestry Operations Department is utilizing Microsoft Access and Excel for system-wide program workflow management, contract invoicing, and data storage. The Company is exploring an opportunity to upgrade to IT-supported systems that integrate cloud technology, support updated data storage and management infrastructure, have an improved user interface, integrate with other tools/data, enable automation opportunities, provide expansion in security and control capability, and allow for near real-time data reporting/visual management capabilities.

Q. Is the Company pursuing advanced remote sensing to improve its forestry model?

A. No, the Company is not pursuing system-wide advanced remote sensing to improve its forestry model at this time. The Company is conducting a small pilot to capture Light Detection and Ranging ("LiDAR") imagery, which was proposed in Case No. U-21585. The purpose of this pilot is to inform and support the execution strategy of LVD line clearing tactics in relatively high-risk wildfire areas. The Company is proposing to continue this pilot annually to evaluate the benefits of utilizing this data on a small scale first, before re-evaluating expanding this LiDAR pilot to a larger scope, up to and including LVD system-wide utilization. This supports the Company's phased approach to imagery analysis utilization: short-to-medium-term utilization of zero-to-low-cost satellite imagery analysis and focused LiDAR pilot projects during the ramp-up to a five-year cycle, and

long-term re-evaluation of larger scope LiDAR acquisition and utilization to further reduce outages once the LVD system is fully on the five-year cycle.

Q. Is the Company planning on using drone technology for its Line Clearing Program?

A. Yes, the Company is exploring the use of drone technology to research opportunities in data collection and analysis through partnership with its Forestry Operations, Unmanned Aircraft Systems, and Geographic Information System departments. Drones are being used by several utilities as a means of collecting various types of high-resolution data in targeted areas. The Company is researching multiple sensor packages (e.g., multispectral, infra-red, and LiDAR) for targeted inspections and documentation of vegetation along the electric system. These technologies have the potential to enhance current practices by identifying declining trees early, detecting the efficacy of herbicide applications, and quantifying tree biomass volume within and along electric corridors.

RELIABILITY BENEFITS OF THE LINE CLEARING PROGRAM

Q. Why is line clearing beneficial to the Company and its electric customers?

A. Trees are the greatest cause of interruptions to electric service for customers on the LVD system and a significant cause of outages or interruptions of electric service on the HVD system. Figure 7 below shows the history of tree-caused interruptions affecting customers from 2020 through 2024 including: (i) the number of outage incidents; (ii) customers interrupted; and (iii) customer minutes of outage. The Company's Line Clearing Program is designed to minimize these occurrences, improve reliable service to its customers, and decrease reactive maintenance and capital expense associated with interruptions during weather events. The Company's proposed five-year cycle strategy will yield significant improvement to customers' electric service.

FIGURE 7
TREE-CAUSED RELIABILITY METRICS 2020 THROUGH 2024
ALL VOLTAGES INCLUDING MEDS (Excluding ITC incidents)

Description	2020	2021	2022	2023	2024
Incidents	18,599	24,163	17,078	18,298	20,326
Customers Interrupted	930,974	1,314,220	919,156	1,037,857	1,084,052
Customer Minutes (M)	494.290	1011.992	444.309	899.756	548.880

The Company's Line Clearing Program also provides benefits that are not easily quantified, such as improved habitat for many plants and animals (including threatened and endangered species) and decreased risk of wildfires from tree contact with conductors. Enhancing the Company's Line Clearing Program will result in less aesthetic impact to customer properties (as clearing will occur more frequently, establishing expectations with property owners) and will improve public safety.

Q. What benefits will customers realize through the requested spending level in the HVD line clearing subprogram?

A. The Company's four-year cycle for HVD line clearing is effectively managing the number of HVD line outage incidents from trees within the right-of-way. The HVD system is the foundation and source for the LVD system. Outages on the HVD system can have broad impacts and can affect large numbers of customers. In the years 2020 through 2024, the average customer impact of a non-MED tree outage incident on an LVD circuit was 45 customers and the average customer impact of a non-MED tree outage incident on an HVD line was 471 customers. HVD line clearing benefits customers by mitigating the amount of these high customer impact outages. Additionally, outages on the HVD lines system often take longer to repair and therefore have higher customer minute impacts.

Maintaining a four-year HVD line clearing cycle is necessary to minimize the impact of HVD tree outages to the LVD system and customers.

Q. What benefits will customers realize through the requested spending level in the LVD line clearing subprogram?

A. The Company's vision outlines a more aggressive plan of increasing the number of miles cleared each year, resulting in a decrease in the number of tree-related outages to the LVD system. Exhibit A-171 (SES-2) illustrates the projected reduction in non-MED and MED tree-caused primary outage incidents, System Average Interruption Frequency Duration ("SAIFI"), and System Average Interruption Duration Index ("SAIDI"). Figures 8, 9, and 10 below show the reliability projections by metric for 2025 through 2030 for the proposed line clearing spending levels to achieve the Company's vision. The values at the top of each bar represent overall reliability projections including MED.

FIGURE 8
PROJECTED 2025-2030 LVD TREE-CAUSED PRIMARY OUTAGE INCIDENTS

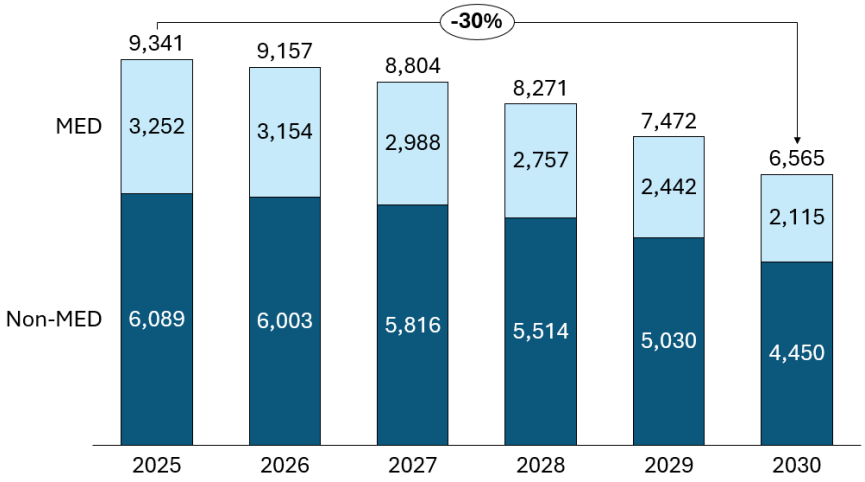


FIGURE 9
PROJECTED 2025-2030 LVD TREE-CAUSED SAIFI DUE TO PRIMARY OUTAGES

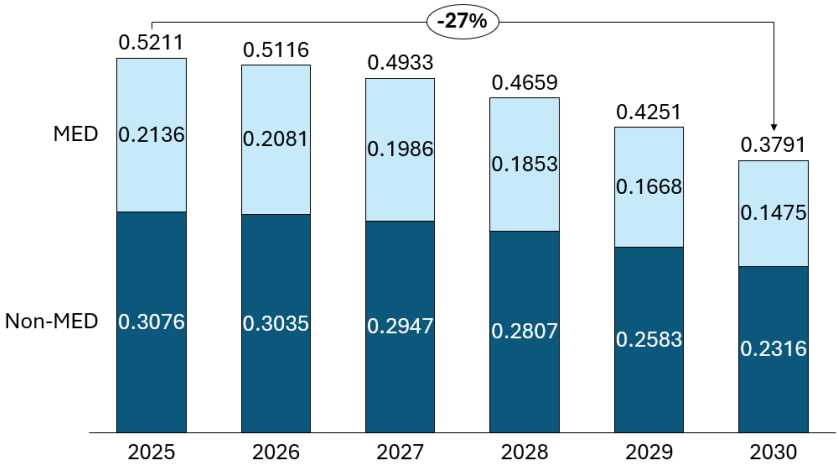
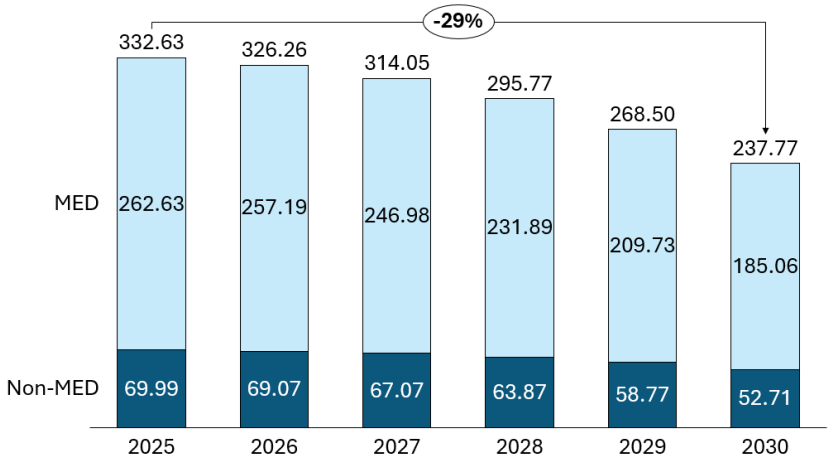


FIGURE 10
PROJECTED 2025-2030 LVD TREE-CAUSED SAIDI DUE TO PRIMARY OUTAGES



The Company's requested LVD line clearing spending level also supports the subprograms described earlier in my testimony that address sections of circuits from protective device to protective device, or protective device to end of circuit, that are experiencing multiple tree-related outage incidents.

Q. What is the source of these reliability projections?

A. The reliability projections in Exhibit A-171 (SES-2) are from the Company's reliability model as described in Company witness Kelly's testimony, page 28, lines 1 through 10. The reliability projections in Exhibit A-171 (SES-2) also factor in the Company's proposed canopy removal on targeted three phase lines.

Q. When will reliability benefits of the new cycle be fully realized?

A. The Company projects that reliability benefits of the new cycle will be fully realized through the second clearing cycle, or roughly by 2036. Liberty's President John Antonuk discussed this phenomenon in his presentation at the Commission's September 26, 2024, meeting,[3] attributing more significant reliability improvement across the second cycle due to a lack of completeness of line clearing work within the first cycle. While the Company agrees that it would likely not see full reliability benefits of the new cycle until the second clearing cycle, it does not agree that this is because its line-clearing work is incomplete. Rather, the partially delayed benefit Mr. Antonuk described may be driven by the lack of "wind firmness" of the surrounding healthy trees remaining after line clearing is performed that were not targeted for removal. My Land Plan, provided by the American Forest Foundation, describes wind firmness as the ability of trees to sway with strong wind~~g~~s without breaking or toppling, and to return to their normal position once a wind gust or storm passes.[4] While the Company has found little to no formal research referencing this concept as it relates to utility line clearing specifically, as most of the research concentrates

[3] Commission Meeting, YOUTUBE (Sept 26, 2024) at ~50:30, https://www.youtube.com/watch?v=QWq5syDj94w ("For vegetation . . . the first cycle, when you advance, uh, when you shorten the cycle for vegetation, it's usually, the work is not as complete or as thorough as the second cycle, so you really, you really should start to see more, much more significant improvement across the second cycle. . . .")
[4] American Forest Foundation, *How Windstorms Affect Your Forest*, My Land Plan, https://mylandplan.org/content/how-windstorms-affect-your-forest.

on general forest management practices, the same principle applies to trees along circuits recently cleared that had not been cleared for many years prior. When many years pass between clearing, trees have more time to grow, and line clearing will result in more significant biomass removal. Trees adapt to the patterns of physical stimulation they experience as they grow,[5] and if trees have experienced a different wind pattern due to the density of surrounding trees, now removed due to line clearing, they must adapt or risk failure. The Company plans to utilize the proposed tree-caused outage review program to gain deeper insights of outage causes to determine if this phenomenon is causing a significant impact to outages post-clearing.

Q. Has the Company considered the benefits of shifting to a four-year fixed line clearing cycle based on the findings of the Analysis as the Commission directed in its recent Order in Case No. U-21585?

A. Yes, the Company has considered the costs and benefits of shifting to a four-year fixed line clearing cycle, and it asserts that the prudent next step in the evolution of its Line Clearing Program is the outlined five-year line clearing cycle, continuing to prioritize residential customer cost-benefit. The Company has compared the estimated costs and projected benefits of achieving a four- and five-year line clearing cycle in the same ramp-up strategy period of this test period through the 2030-2031 test period. The Company estimates that achieving a four-year cycle in the same timeframe could raise expenses nearly 15% overall, with some years as high as 23%. In its comparison, the Company assumed a 0% change in expenses in this test period as it has projected the most aggressive crew resourcing plan

[5] Amanda Bunce, *Wind and Trees 101: To Touch a Tree, Stormwise Forest Management*, University of Connecticut College of Agriculture, Health, and Natural Resources & School of Engineering (May 8, 2017), https://stormwise.uconn.edu/2017/05/08/wind-and-trees-101-to-touch-a-tree/

it believes it can achieve in the first year. The Company estimates that this increased spending could result in only 3% additional reliability benefit across multiple metric types due to diminishing returns.

It is important to note that, to increase line clearing miles in this ramp-up timeframe, the majority of the incremental expense is due to increasing out-of-state tree crewing. This resource is a more expensive resource than local tree crewing. Once the Company is on a five-year cycle, it projects the need for out-of-state tree crewing is eliminated due to the efficiencies a shorter cycle brings. The incremental cost of moving from a five-year cycle to a four-year cycle may be prudent in the future; however, the Company's LVD system is not currently on a five-year cycle, and significant out-of-state resources would be necessary to bring the system to an even shorter four-year cycle at this time. Once the five-year cycle is attained, the Company will reevaluate other tactics for continuous improvement in risk management, including cycle considerations.

Q. What reliability benefit is attributed to canopy removal?

A. The Company estimates it would see a 4% reduction in primary tree-caused incidents from canopy removal on targeted three phase lines.

Q. How was the reliability benefit of canopy removal calculated?

A. The Company utilized benchmarking data found in Exhibit A-177 (SES-8)[6] indicating a 6% outage reduction opportunity through canopy removal. Because the Company is proposing to remove canopy along a portion of its LVD primary, and it estimates this portion of LVD primary impacts 2/3rds of customers impacted by tree-caused outages, it

[6] Page 27, Figure 6-4 (Permission to use this study was obtained from its authors).

applied this 6% reduction across roughly 2/3rds of customers interrupted by tree-caused events. This results in a calculation of a 4% tree-caused reliability improvement overall.

EXPENSE REQUIREMENTS FOR THE LINE CLEARING PROGRAM VISION

Q. What are the projected expense requirements to maintain the HVD system on its four-year cycle?

A. The projected expense requirements to maintain the HVD system on its four-year cycle are displayed in Figure 11 below:

FIGURE 11
HVD LINE CLEARING SCHEDULE

Calendar Year	Data Type	O&M Maintenance Clearing Miles	Capital Clearing Miles	O&M Expense ($M)	Capital Contractor Costs ($M)	Local Crews
2020	Actual	1,116	46	$9.17	$1.18	41
2021	Actual	1,178	89	$10.74	$1.80	42
2022	Actual	1,106	70	$10.99	$0.80	38
2023	Actual	1,153	29	$11.30	$0.53	38
2024	Actual	1,203	78	$10.73	$2.43	38
2025	Projected	1,104	129	$12.20	$4.12	38
2026	Projected	1,177	138	$11.99	$4.49	38
2027	Projected	1,162	138	$11.55	$4.58	38
2028	Projected	1,120	138	$11.20	$4.66	38
2029	Projected	1,167	138	$11.40	$4.75	38
2030	Projected	1,177	138	$11.60	$4.83	38

Q. What are the projected expense requirements for the LVD system ramp-up to achieve the Line Clearing Program vision of a five-year clearing cycle and more aggressive line clearing on targeted three phase lines?

A. The projected expense requirements for the ramp-up to achieve the LVD Line Clearing Program vision are displayed in Figure 12 below:

FIGURE 12
LVD LINE CLEARING RAMP-UP SCHEDULE

Calendar Year	Data Type	O&M Full-Circuit Clearing Miles	O&M Subprogram Clearing Miles	O&M Subprogram Spray Miles	Capital Clearing Miles	O&M Expense ($M)	Capital Contractor Costs ($M)	Local Crews	Out-of-State Crews	Total Crews
2020	Actual	3,679	294	238	258	$46.10	$5.67	220	0	220
2021	Actual	4,647	238	395	252	$75.83	$6.07	299	0	299
2022	Actual	5,653	247	488	221	$91.02	$6.71	334	0	334
2023	Actual	5,758	165 ~~244~~	443	169 ~~8~~	$97.79	$5.59	348	0	348
2024	Actual	5,400	209 ~~244~~	421	270 ~~258~~	$99.49	$9.69	347	0	347
2025	Projected	6,108	244	413	325	$113.20	$14.01	364	0	364
2026	Projected	7,891	199	405	325	$152.97	$14.29	403	53	456
2027	Projected	10,885	149	454	325	$201.75	$14.57	420	120	540
2028	Projected	12,814	137	501	325	$226.28	$14.87	420	158	578
2029	Projected	13,588	75	491	325	$230.43	$15.16	420	158	578
2030	Projected	14,837	75	508	325	$236.81	$15.47	420	158	578

Q. What expense is the Company projecting to maintain the five-year clearing cycle after it is achieved?

A. The Company's current projection for the annual expense to maintain the five-year cycle after it is achieved in the 2030-2031 test period is $180.359 million ($168.525 million of which are LVD expenses) and subject to inflation in years after. The Company is referring to this measure as the baseline expense.

Q. What baseline expense requirement is the Company projecting for the test period?

A. The Company projects a baseline expense requirement of $164.446 million ($152.606 million of which are LVD expenses) for the test period.

Q How were the baseline expense requirement for the test period and the baseline expense for the years leading up to achieving the five-year cycle calculated?

A. The baseline expense requirement for the test period of $164.446 million was calculated utilizing the Company's current projection for the annual expense to maintain the five-year cycle after it is achieved in the 2030-2031 test period, adjusted to test period dollars.

Figure 13 below shows the outcome of this calculation methodology for the calendar years leading up to achieving the five-year cycle.

FIGURE 13
PROJECTED LINE CLEARING PROGRAM EXPENSES AND BASELINE EXPENSE REQUIREMENTS

12-Month Timeframe	Total O&M Expense ($M)	Baseline O&M Expense ($M)
2026 Calendar	$164.953	$163.357
2027 Calendar	$213.300	$166.624
2028 Calendar	$237.485	$169.956
2029 Calendar	$241.826	$173.356
2030 Calendar	$248.414	$176.823
U-21870 Test Period	$186.684	$164.446
Post-Vision	$180.359	$180.359

Q. Why is this baseline expense requirement different than the five-year cycle estimation in the Analysis?

A. In the Analysis, the Company estimated an annual expense to maintain the LVD system on a five-year cycle in a steady state (once the cycle had already been achieved and there are no backlog miles that have gone longer than the cycle length between clearing) of $134.441 million.[7] This value is different than the LVD baseline expense requirement in Exhibit A-170 (SES-1), column (q), line 12, of $152.606 million. There are refined and updated assumptions that have impacted this projection, including overall crew resourcing, and the consideration of overtime for both local and out-of-state tree crews. Another notable difference in these values is that the Analysis utilized the timeframe of one year using costs inflated to 2024, whereas the baseline expense requirement in Exhibit A-170 (SES-1) is adjusted to the test period for this case.

[7] The Analysis, Attachment 3, column (g), line 42

Q. What level of spending is the Company proposing for the 2026 calendar year and the test period for its Line Clearing Program?

A. As discussed below in greater detail under each subprogram of my direct testimony, the Company is proposing to spend $164.953 million for line clearing in the 2026 calendar year and $186.684 million for line clearing in the test period, as shown in Figure 14 below and in Exhibit A-170 (SES-1).

FIGURE 14
LINE CLEARING EXPENSES
2026 CALENDAR YEAR AND TEST PERIOD

Categories	2026 Calendar Total O&M Expenses	Test Period Total O&M Expenses
HVD Line Clearing	$10,910,683	$10,755,522
LVD Line Clearing	$144,782,420	$164,864,105
Line Clearing Admin	$9,260,324	$11,064,347
Total	**$164,953,427**	**$186,683,974**

Q. What is the line item in Figure 14 titled Line Clearing Admin?

A. Line Clearing Admin is the internal salaries and expenses of the Company's Forestry Operations Department, which administers the contracts and oversees the performance of the Company's line clearing contractors. It also includes the contract foresters and work planners utilized through a contract with ArborMetrics Solutions LLC that plan the work and interact with customers. This amount for the 2026 calendar year is reflected in Exhibit A-170 (SES-1), column (j), lines 30, 31, and 32.

Q. What inflationary rates were used to determine the projections in Figure 14?

A. The Company's internal labor expenses for Forestry Operations shown in Figure 14 and Exhibit A-175 (SES-6) are a combination of current staffing, anticipated retirements, replacement and new hiring, merit increases, and contracted planning resources. Please

refer to the direct testimony of Company witness Patrick D. Daly, page 14, lines 9-11, and page 15, lines 1-2, for details on the Company's projected merit and inflationary rates, which were utilized for Line Clearing Admin expense projections. All contractor rates are contractually limited through mid-2029 to an annual adjustment of a minimum of 0.0% per year up to a maximum of 2.5% per year based on the Producers Price Indices WPUFD4 and WPU443. Figure 15 below shows the 2024 results for Producers Price Indices WPUFD4 and WPU443 published January 14, 2025.

FIGURE 15
PPI COMMODITY DATA FOR ANNUAL CONTRACTOR RATE ADJUSTMENT

PPI Commodity Data
12-Month Percent Change
Series Id: WPUFD4
Not Seasonally Adjusted
Series Title: PPI Commodity data for Final demand, not seasonally adjusted
Group: Final demand
Item: Final demand
Base Date: 200911
Years: 2019 to 2024

	Percent Change												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Annual**
2019	1.9	1.9	2.0	2.4	2.1	1.6	1.6	1.9	1.5	1.0	1.0	1.4	1.7
2020	2.0	1.1	0.3	-1.5	-1.1	-0.7	-0.3	-0.3	0.3	0.6	0.8	0.8	0.2
2021	1.6	3.0	4.1	6.5	7.0	7.6	8.0	8.7	8.8	8.9	9.9	10.0	7.0
2022	10.1	10.4	11.7	11.2	11.1	11.2	9.7	8.7	8.5	8.2	7.4	6.4	9.5
2023	5.7	4.7	2.7	2.3	1.1	0.3	1.1	1.9	1.8	1.1	0.8	1.1	2.0
2024	1.0	1.6	2.0	2.3	2.5	2.9	2.4	2.1	2.1	2.6	3.0	3.3	2.3

PPI Commodity Data
12-Month Percent Change
Series Id: WPU443
Not Seasonally Adjusted
Series Title: PPI Commodity data for Rental and leasing of goods (partial)-Construction, mining, and forestry machinery
Group: Rental and leasing of goods (partial)
Item: Construction, mining, and forestry machinery and equipment rental and leasing
Base Date: 200903
Years: 2019 to 2024

	Percent Change												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Annual**
2019	-0.1	-1.4	-0.9	0.4	1.8	1.9	0.8	0.8	0.1	-0.5	-1.1	-1.3	0.0
2020	-1.6	-1.7	-0.1	-1.1	-1.9	-2.4	-3.8	-3.3	-4.4	-4.6	-4.3	-4.6	-2.8
2021	-4.8	-4.6	-4.0	-2.6	-2.5	-2.4	-0.4	-0.4	1.0	1.4	2.0	2.1	-1.3
2022	1.9	2.5	1.4	1.6	3.3	4.9	4.4	7.5	7.3	7.1	6.5	8.1	4.7
2023	9.8	9.2	9.2	9.3	7.7	5.8	6.3	2.2	2.5	2.7	2.5	1.2	5.6
2024	-0.1	-1.0	0.5	0.1	-0.8	0.0	-0.4	1.0	0.8	0.4	0.6	0.0	0.1

Q. What is the Company's projected 2026 calendar year and test year spending level, for which it is requesting cost recovery, in the HVD line clearing subprogram?

A. The Company is projecting HVD line clearing expenses of $11.987 million in the 2026 calendar year and $11.840 million in the test period, as shown in Figure 16 below and in Exhibit A-170 (SES-1).

Q. How would these projected expenses be allocated among the categories of work described above?

A. The Company is projecting expenses in the 2026 calendar year and test period for each category as identified in Figure 16 below:

FIGURE 16
HVD LINE CLEARING EXPENSES
2026 CALENDAR YEAR AND TEST PERIOD

	2026 Calendar		Test Period	
Categories	**Expenses**	**Line Miles**	**Expenses**	**Line Miles**
Maintenance clearing	$4,886,488	587	$4,870,358	584
Brush control	$5,869,195	586	$5,730,163	584
Demand	$60,000	4	$60,000	4
Noxious weed control	$95,000	n/a	$95,000	n/a
Line Clearing Admin	$1,076,037	n/a	$1,084,138	n/a
Total	**$11,986,720**	**1,177**	**$11,839,660**	**1,172**

Q. What spending level for the HVD line clearing subprogram was approved in the Company's last electric rate case order?

A. In MPSC Case No. U-21585, the Company requested a line clearing spending level of $125.086 million. Company witness Pamela L. Bolden testified in that case that the HVD allocation would be $12.294 million for the 2025 calendar year and $11.972 million for the 2026 calendar year, which equated to $12.240 million in the 2025 test period (March 2025 through February 2026).

Q. Does the Company request to recover the entirety of its HVD line clearing O&M spending in the test period through base rates?

A. Yes, it does.

Q. What is the Company's projected 2026 calendar year and test year spending level, for which it is requesting cost recovery, in the LVD line clearing subprogram?

A. The Company is projecting LVD line clearing expenses of $152.967 million in the 2026 calendar year and $174.844 million in the test period, as shown in Figure 17 below, and in Exhibit A-170 (SES-1).

Q. How would these projected expenses be allocated among the categories of work described above?

A. The Company is projecting expenses in the 2026 calendar year and test period for each category as identified in Figure 17 below:

FIGURE 17
LVD LINE CLEARING EXPENSES
2026 CALENDAR YEAR AND TEST PERIOD

	2026 Calendar		Test Period	
Categories	**Expenses**	**Line Miles**	**Expenses**	**Line Miles**
Full Circuit Clearing	$135,674,820	7,891	$156,029,100	9,019
Repetitive Outage	$1,057,600	40	$1,005,067	36
CEMI Clearing	$500,000	34	$450,000	31
First Zone Clearing	$1,000,000	55	$883,333	50
LCP Zonal Clearing	$800,000	27	$729,938	24
Demand Work	$2,250,000	44	$2,100,000	40
Brush Control	$3,500,000	405	$3,666,667	422
Line Clearing Admin	$8,184,287	n/a	$9,980,209	n/a
Total	**$152,966,707**	**8,496**	**$174,844,314**	**9,622**

Q. What expense is associated with more aggressive line clearing on targeted three phase lines?

A. The expense associated with more aggressive line clearing on targeted three phase lines is contained in the full circuit clearing category of work in the amount of $4.172 million for the 2026 calendar year spending level, which is eight months (8/12ths) of the test period incremental expense, shown as Year 1 in Figure 18 below.

Q. How was the expense associated with more aggressive line clearing on targeted three phase lines calculated?

A. The Company estimates that one-fifth of the targeted three phase lines, or about 1,100 miles, will have canopy removal each year through the five-year vision timeframe. In its canopy removal study in 2022, the Company observed an average contractor cost increase of 35% per mile cleared. This cost assumption was utilized across the 1,100 estimated annual miles considering the percentage of total hours worked by local crews and out-of-state crews and an assumed split of on-cycle miles and backlog miles. The vision miles and incremental expense for canopy removal on targeted three phase lines is displayed in Figure 18 below:

FIGURE 18
VISION MILES AND INCREMENTAL EXPENSE FOR CANOPY REMOVAL ON TARGETED THREE PHASE PRIMARY

Vision Year	Cycle Miles	Backlog Miles	Total Miles	Incremental Cost per Mile	Incremental Canopy Removal Expense ($M)
Year 1	550	550	1,100	$5,689	$6.258
Year 2	660	440	1,100	$5,553	$6.108
Year 3	770	330	1,100	$5,320	$5.852
Year 4	880	220	1,100	$5,136	$5.649
Year 5	990	110	1,100	$4,909	$5.399
Total	**3,850**	**1,650**	**5,500**	**$5,321**	**$29.267**

Q. What spending level for the LVD line clearing subprogram was approved in the Company's recent electric rate case orders?

A. The approved spending level for the LVD line clearing subprogram in the Company's recent electric rate case orders is outlined in Figure 19 below:

FIGURE 19
LVD LINE CLEARING AUTHORIZED SPEND

MPSC Case No.	Timeframe	LVD Authorized Spend ($M)
U-20697	January 2021 - December 2021	$71.430
U-20963	January 2022 - December 2022	$81.089
U-21224	January 2023 - December 2023	$87.966
U-21389	March 2024 - February 2025	$106.608
U-21585	March 2025 - February 2026	$113.168[8]

[8] Includes wildfire risk mitigation expenditures.

Q. Has the Company met its commitment to spending the authorized amounts for the Line Clearing Program in MPSC Case Nos. U-20697, U-20963, U-21224, U-21389, and U-21585?

A. Yes, the Company has met its commitment to spend the authorized amounts for the Line Clearing Program in MPSC Case Nos. U-20697, U-20963, U-21224, and U 21389. In the test period for Case No. U-21585 (March 2025 through February 2026), the Company plans to spend $125.087 million for its Line Clearing Program and an additional $0.321 million for wildfire risk mitigation line clearing as projected in Company witness Kelly's Exhibit A-114 (MPK-22) in Case No. U-21585 and the Commission's Order in that case dated March 21, 2025, page 93. Figure 20 below outlines each MPSC Case No. authorized spend and actual spend. Over this timeframe, the Company invested $19.973 million in its Line Clearing Program above the authorized spend amount.

FIGURE 20
LINE CLEARING PROGRAM SPEND AUTHORIZED TO ACTUAL

MPSC Case No.	Timeframe	Authorized Spend ($M)	Actual Spend ($M)	Difference in Authorized Spend and Actual Spend ($M)
U-20697	January 2021 - December 2021	$84.000	$86.567	$2.567
U-20963	January 2022 - December 2022	$93.959	$102.003	$8.044
U-21224	January 2023 - December 2023	$100.030	$109.093	$9.063
U-21389	March 2024 - February 2025	$118.890	$119.189	$0.299
U-21585	March 2025 - February 2026	$125.408[9]	$125.408[10]	$0.000
Total	January 2021 - February 2026	$522.287	$542.260	$19.973

[9] Includes wildfire risk mitigation expenditures.
[10] Projected spend.

Q. How did the Company project spending for the 2025 calendar year, the 2026 calendar year, and the test period (May 1, 2026 through April 30, 2027)?

A. The 2025 calendar year spending projection in the Company's 2024 Electric Rate Case No. U-21585 totaled $125.408 million for both LVD and HVD programs, including wildfire risk mitigation expenditures. The Company sought an increase for the 2025 calendar year based on the fifth year of the five-year spending plan presented in MPSC Case Nos. U-20697, U-20963, U-21224, and U-21389 with adjustments in the HVD and LVD subprogram totals from previous filings. For this case, projected test period spending was derived from operational intelligence by Forestry Operation's Senior Manager, Manager of Strategic Planning and Performance, and other staff members. Values presented in Exhibit A-170 (SES-1) are the Forestry Operation team's projections, informed by historical costs per mile cleared, current system work estimates, crew availability and work schedules, and other factors to maintain clearing on the HVD system at current level and to reduce the clearing cycle on LVD. As average monthly spending is not consistent during a significant ramp-up period (i.e., crewing may sharply increase at any one time when availability permits), the test period for this case (May 1, 2026 through April 30, 2027) presented in Exhibit A-170 (SES-1) is not calculated using ratios of eight months ($8/12^{th}$) of the 2026 calendar year and four months ($4/12^{th}$) of the 2027 calendar year, but instead driven by the aforementioned operational intelligence (e.g., striking an appropriate rate of crew ramp-up based on vendor availability, field planning resources, and supervision).

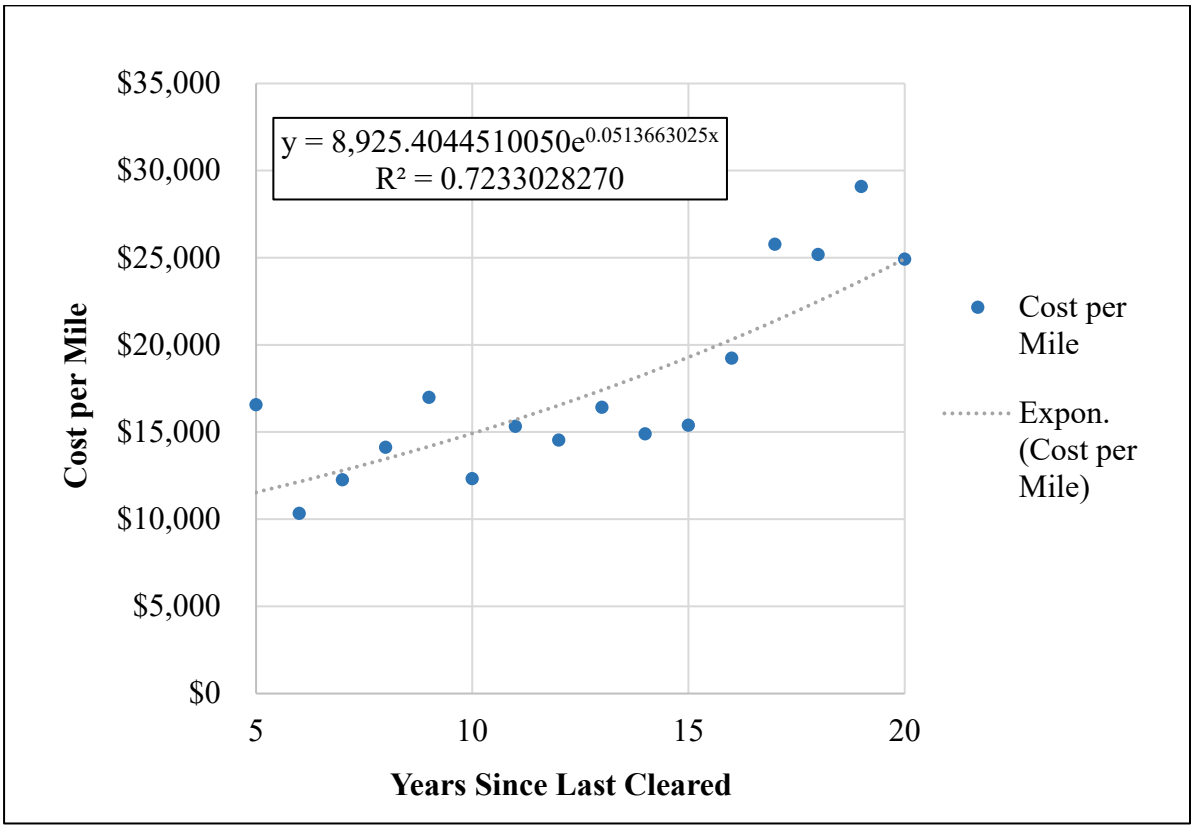
Q. For the test year, what will happen to dollars remaining if the HVD workplan is completed under budget?

A. If the HVD workplan is completed under budget, any remaining dollars for the test year will be allocated to the LVD system to support the Company's vision of attaining a five-year cycle by the end of the 2030-2031 test period while still maintaining the HVD system on its four-year cycle.

Q. Does a shorter clearing cycle reduce the average cost per line mile to clear circuits?

A. Yes, the Company's data supports that a shorter clearing cycle results in a lower average cost per line mile to clear circuits. Longer clearing cycles result in more complex clearing work and require the removal of more biomass to achieve clearance to conductors, as the vegetation has had more time to grow between clearings. To inform its expense projections for its vision, the Company considered lower costs per mile to maintain circuits on a shorter cycle. Figure 21 below shows the relationship between clearing costs per mile and the number of years between clearings utilizing the most recently available full circuit clearing data from 2024 on circuits last cleared 5 to 20 years earlier. It is important to note that there is more available data on longer durations between clearings as the Company has been working to reduce the LVD backlog. Some data exists for shorter durations between clearings to inform this trend and more will become available as the Company's vision includes performing clearing on more cycle circuits starting in 2026, preventing cycle circuits from becoming backlog circuits. This data will continue to be refined, and expense projections updated accordingly.

FIGURE 21
2024 CONTRACTOR FULL CIRCUIT CLEARING COST PER LVD MILE BASED ON YEARS SINCE LAST CLEARED



Q. What are the historical unit costs for the Company's O&M clearing work in the LVD line clearing subprogram?

A. Unit costs over the last five years are provided in Figure 22 below:

FIGURE 22
LVD LINE CLEARING UNIT COSTS

Description	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024
O&M Cleared Miles	4,211	5,279	6,388	6,365	6,030
O&M Expense ($M)	$46.10	$75.83	$91.02	$97.79	$99.49
$/line mile	$10,948	$14,364	$14,248	$15,364	$16,499

Q. Please explain the increase in unit costs in recent years.

A. Unit costs decreased significantly in 2020 due to coronavirus pandemic restrictions with decreases in customer interactions with line clearing crews and forestry operations personnel about the planned line clearing work. This permitted clearing operations to proceed in an efficient manner without work stoppages or delays to address customer concerns in the field. As predicted in MPSC Case No. U-20963, the unit cost returned to "normal" levels in 2021 with additional increases as described below.

The greatest impact on unit costs for 2021 and 2022 was the ramp-up with many new contractor employees and vendors new to the utility line clearing business. New employees are less productive until their skill levels develop to optimal performance while maintaining safety protocols. Secondly, the addition of new Michigan-based vendors, all of which are smaller scale operations compared to the large nationwide utility line clearing contractors, increased unit costs as their business cost structures are much different than the nationwide vendors. In time, as these Michigan-based vendors grow, their cost structures will align more closely to the nationwide vendors and unit costs will decrease.

The greatest impact on unit costs for 2023 was a higher percentage of more expensive supplemental vendor crews compared to base crews and a higher percentage of backlog circuit miles cleared than anticipated; these additional backlog circuit miles were selected and added with the $8.0 million in one-time funding from MPSC Case No. U-21332.

The greatest impact on unit costs for 2024 was new line clearing contracts executed in the second quarter of 2024. The Company experienced an approximate 12% increase

above inflation in the base rates for line clearing contractors for 2024 when these new contracts went into effect.

Q. Does the Company request to recover the entirety of its LVD line clearing O&M spending in the test period through base rates?

A. No, it does not.

Q. Is the Company proposing an alternate mechanism to fund LVD Line Clearing O&M in the test period?

A. Yes, the Company is proposing regulatory asset treatment for the funding requirement for the test period above baseline expenditures, identified in Exhibit A-170 (SES-1), column (p), line 27. Figure 23 below summarizes the total O&M expense, baseline expense, and regulatory asset proposal amounts for the test period. This proposed alternate funding mechanism is discussed in further detail in Company witness Daly's testimony on page 34, line 18, through page 36, line 20.

FIGURE 23
LINE CLEARING O&M ALTERNATE FUNDING MECHANISM PROPOSAL
TEST PERIOD

Description	HVD	LVD	Total
Total O&M Expense	$11,839,660	$174,844,314	$186,683,974
Baseline Expense	$11,839,660	$152,606,207	$164,445,867
Regulatory Asset	$0	$22,238,107	$22,238,107

RESOURCING PLAN FOR THE LINE CLEARING PROGRAM VISION

Q. Does the Company currently have the personnel and other resources to complete the projected HVD line clearing work if the Commission approves the requested spending level?

A. Yes, the Company currently has the resources in place to maintain the HVD system on a four-year clearing cycle.

Q. Does the Company currently have the personnel and other resources to complete the projected LVD line clearing work if the Commission approves the requested spending level?

A. No. At the time of this filing, the Company has not yet secured the personnel and other resources required to execute the full requested spending level, which is an increase over recent annual expenses and current personnel and resourcing levels.

Q. How does the Company plan to meet the personnel and other resource requirements to complete the projected LVD line clearing work if the Commission approves the requested spending level?

A. A great issue for resource planning is certainty of funding. While the Company will not execute its plans to secure additional personnel and other resources until certainty is attained, the Company is preparing to do so for the test period. The Company has identified three focus areas for this preparation: (i) line clearing contractors; (ii) contract planning and supervision; and (iii) internal staffing.

To ensure the necessary crewing is attained, the Company is working with established line clearing contractors to upskill current and hire additional employees to increase the local crew baseline resourcing level. Additionally, the Company is pursuing contracts with supplemental line clearing contractors to provide out-of-state tree crews to meet the increased crew resourcing level needed to execute the ramp-up plan. Figure 24 below outlines actual crewing from 2020 through 2024 and the projected crewing plan for 2025 through 2030.

FIGURE 24
HVD AND LVD LINE CLEARING CREWING

		HVD	LVD		
Calendar Year	**Data Type**	**Local Crews**	**Local Crews**	**Out-of-State Crews**	**Total Crews**
2020	Actual	41	220	0	261
2021	Actual	42	299	0	341
2022	Actual	38	334	0	372
2023	Actual	38	348	0	386
2024	Actual	38	347	0	385
2025	Projected	38	364	0	402
2026	Projected	38	403	53	494
2027	Projected	38	420	120	578
2028	Projected	38	420	158	616
2029	Projected	38	420	158	616
2030	Projected	38	420	158	616

The Company's Forestry Operations and Supply Chain departments are collaborating with its established contract planning vendor for additional planning and supervision resources as well as supplemental contract planning vendors to meet the increased personnel level needed to execute the ramp-up plan.

For in-house staffing, the Company continues to recruit graduates from Michigan Technological University, Michigan State University, and other universities that offer degrees in forestry and/or natural resource management. The plan for internal staffing during the ramp-up is set to meet a level to support the baseline to maintain the steady-state five-year cycle; during the ramp-up period, the Company will utilize contract personnel to meet the increased staffing needs over the baseline resourcing level starting in the test period through the five-year vision.

Q. How does the Company plan to ramp up its LVD line clearing spending and full circuit clearing work for the 2026 calendar year and test period?

A. The projected 2026 calendar year increase in O&M expense and LVD full circuit clearing miles is provided in Figure 12 above and in Exhibit A-170 (SES-1) for the test period. As Figure 12 indicates, in the 2026 calendar year, the Company projects to clear 7,891 miles in its full circuit clearing subprogram, which is 1,783 more miles (29% higher) than the projected 2025 full circuit clearing mileage. The Company projects that it will need 92 additional contractor line clearing crews above the 2025 crewing level to accomplish this plan in the 2026 calendar year. In partnership with its current vendors under terms established with new contracts executed in the second quarter of 2024, and through the engagement of supplemental vendors, the Company expects to meet this required crewing level.

Q. Does this conclude your direct testimony in this case?

A. Yes, this concludes my direct testimony.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

SARA E. STEWART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Sara E. Stewart, and my business address is 1945 W. Parnall Road, Jackson, MI 49201.

Q. Are you the same Sara E. Stewart who previously presented direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will rebut the assertions and recommendations of the Association of Businesses Advocating Tarriff Equity ("ABATE") witness Jessica A. York, Michigan Public Service Commission ("MPSC") Staff ("Staff") witness Jessica Duell, and Attorney General ("AG") witness Sebastian Coppola regarding the Consumers Energy Company's ("Consumers Energy" or the "Company") line clearing program.

Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?

A. No.

REBUTTAL OF ABATE WITNESS YORK

Q. Ms. York states her concern on page 15, line 11, of her direct testimony. Do you agree that the Company's High Voltage Distribution ("HVD") Line Clearing Program projected Operating and Maintenance ("O&M") spending is overstated?

A. No, I do not agree that the projected O&M spending for HVD Line Clearing is overstated. As the HVD system is on a four-year cycle, in 2026 the Company will need to clear line segments it cleared in 2022, *plus* additional line segments close in proximity that have been adjusted into 2026's workplan to support crew efficiency. Not only are there more miles to complete in 2026 than in 2022, but the Company also executed new line clearing contracts

in 2024 and experienced an increase in the base rates for line clearing contractors, which impacts HVD line clearing work.

Q. Should the Company be disallowed 10% of its projected test year HVD Line Clearing O&M, or $1.184 million?

A. No. The Company projects spending the full proposed amount on HVD Line Clearing in the test period. In the event the Company completes its HVD workplan spending less than the full proposed amount, it will reallocate any net decrease in HVD clearing costs for the test year to the Low Voltage Distribution ("LVD") system to support bringing the LVD system to its intended cycle, as it has historically done. The Company followed this historical practice (reallocating any net decrease) from 2020 to 2024 – the period that Ms. York discussed in her testimony. This historical practice, which the Company plans to continue, should alleviate any concern about a potential net decrease in HVD clearing costs.

REBUTTAL OF STAFF WITNESS DUELL

Q. Ms. Duell states Staff's opinion on page 9, lines 15 through 17, that the Company did not prioritize its line clearing program highly enough in the past. Does the Company agree with this statement?

A. No, the Company has demonstrated its commitment to its Line Clearing Program consistently since Case No. U-20697 where the Company first proposed the seven-year effective cycle for its LVD system. In that case and subsequent cases, the Company has been transparent with its current state of backlog circuits and its plan to eliminate the backlog, with a commitment to prioritize poorly performing circuits for line clearing. With the support of the Commission and Staff, the Company began working toward the seven-year effective cycle in the 2021 test period and continued with this strategy through

Case No. U-21585. As outlined in my direct testimony in Figure 20 on page 43, the Company has exceeded its authorized spending levels in all cases since Case No. U-20697. In the instant case, the Company is pursuing a path of continuous improvement in its proposal to ramp-up LVD line clearing to a five-year cycle, showing continued prioritization of this program.

Q. On page 12, lines 26 through 28, of her direct testimony, Ms. Duell states the Company underspent in line clearing in 2024 [calendar year] and cleared fewer miles than proposed and approved for line clearing expenses in Case No. U-21585. Do you agree?

A. No, I do not agree. The Company met and exceeded its authorized line clearing expense level for the 2024 test period (12 months ending 2/28/2025), which was authorized in the Order for Case No. U-21389. In comparison to the Case No. U-21389 test period (12 months ending 2/28/2025) authorized funding of $118,889,334, the Company spent $119,189,032 toward the Line Clearing Program.

While the Company forecasts calendar year spend, the authorized line clearing expense level is associated with the test period, and not to a calendar year. As discussed in my direct testimony on page 44, lines 14 through 20, it is operationally challenging to meet both a projected calendar year spending level and test year spending level that do not directly overlap in timeframe, especially when expense levels are increasing from one test period to the next test period.

Q. On page 13, lines 3 through 5 of her direct testimony, Ms. Duell states the Company did not answer where the $5,876,252 in remaining funding was allocated to. Do you agree?

A. No, the Company did answer this question in discovery response U21870-ST-CE-0116 as shown in Exhibit S-18, page 1. It is possible that Ms. Duell has unintentionally conflated the 2024 calendar year with the Case No. U-21389 test year. As mentioned, the Company is committed to meeting the authorized line clearing expense level associated with the test period as defined by Orders or Settlement Agreements.

Q. On page 13, lines 24 through 27, and page 14, lines 1 through 3, of her direct testimony, Ms. Duell shares a concern that the Company is experiencing contractor shortages. Is the Company experiencing contractor shortages?

A. No, the Company is not experiencing contractor shortages. In discovery response U21870-ST-CE-0117, as shown in Exhibit S-18, page 9, I stated the Company cleared fewer miles in 2024 than projected due to execution of new LVD contracts in May 2024, resulting in a higher unit cost per mile. This is not synonymous with a contractor shortage.

Q. On page 11, lines 15 through 22, Ms. Duell attributes the scope of the Company's canopy removal proposal to everything past the first zone. Is this accurate?

A. No, this is not accurate. As discussed in my direct testimony on page 23, lines 11 through 16, the Company is proposing that zone number alone not be the determining factor for canopy removal, but the consequence of failure of the section of line in question be the driving factor, which will include some second zones and may even extend past the second zone depending on the zone attributes. This scope also inherently includes many first zones as it targets the path of substation-to-substation connection to enable switching

opportunities during outage events (i.e. line crew enablement to isolate the fault location, restore some customers impacted by the outage, perform repairs, then fully restore all customers impacted by the outage), but it may not include 100% of first zones depending on individual zone attributes.

Q. On page 12, lines 16 through 19, Ms. Duell states that Staff initially interpreted my testimony as stating the Company removed all canopy in the first zone 100% of the time. Has the Company stated in testimony it removes all canopy in the first zone 100% of the time?

A. No. In my direct testimony on page 8, lines 20 through 23, I state that overhanging branches above conductors during first zone clearing are considered for removal, which is not indicative of 100% of the time. Later in my testimony on page 21, lines 10 through 15, I compare the Company's canopy removal proposal for targeted three-phase primary lines to the Company's general line clearing specification, which clearly states some canopy has been allowed to remain over LVD primary lines.

Q. On page 10, line 25, Ms. Duell states that Staff recommends the Company clear all canopy in the first zone. Do you agree that the Company should begin clearing all canopy in the first zone starting in the instant case test period?

A. No, I do not agree the Company should begin clearing all canopy in the first zone starting in the instant case test period. The scope of the Company's proposal for canopy removal is defined in my direct testimony on page 23, lines 1 through 16. While this proposed scope includes some three-phase mileage in first zones, it does not include 100% of first zones (e.g. it does not include single and two-phase unfused laterals off three-phase first zone). The funding level needed to execute canopy removal for both the Company's scope and

Ms. Duell's recommendation of all first zones is not reflected in the revenue requirement for the Line Clearing Program in the instant case.

Q. Would the Company consider clearing all canopy in the first zones of LVD circuits in a future electric rate case?

A. Yes, the Company is agreeable to considering clearing all canopy in the first zones of LVD circuits by performing an updated analysis on both the projected costs and benefits in a future electric rate case. As adding all first zones for canopy removal is an expansion upon the proposed scope of canopy removal in the instant case, the Company recommends that it be granted time to execute some canopy removal and allow these targeted three-phase lines time to begin collecting reliability data toward a statistically significant cost-benefit analysis.

Q. On page 9, lines 7 through 10, and page 14, lines 9 through 10, Ms. Duell states the Company did not provide a new analysis that considered the benefits of shifting to a fixed 4-year line clearing cycle. Did the Company conduct this analysis?

A. Yes, the Company conducted this analysis and its conclusion is in my direct testimony on page 32, lines 10 through 21, and page 33, lines 1 through 13. This analysis included projected costs, a timing assumption, and projected reliability improvement. Based on my analysis, I concluded that moving to a four-year cycle in the timeframe the Company proposed to move to a five-year cycle could increase expenses by 15% overall while adding only 3% to the total reliability benefits across multiple metric types.

Q. On page 14, line 30, and page 15, lines 1 through 3, Ms. Duell states the Company relies on the formal optimization analysis of line clearing cycles report to determine if a four-year effective line clearing cycle is efficient or not. Is this true?

A. No, the Company did not utilize the Formal Optimization Analysis of Line Clearing Cycles in the instant case when considering the benefits of shifting to a four-year fixed line clearing cycle. Rather, the Company utilized the same methodology to evaluate a four-year cycle that it used to evaluate the cost and benefit projections of shifting to a five-year line clearing cycle in the same ramp-up strategy period (i.e. the test period of the instant case through the 2030-2031 test period). In comparison, the Formal Optimization Analysis of Line Clearing Cycles assumed steady-state costs to maintain each cycle length analyzed (i.e. assumes the cycle has already been achieved for each cycle length), whereas the Company's analysis in the instant case assumed the current state of the LVD system and projected costs to move it to a four-year cycle.

Q. Should the Company file a new analysis of the costs and benefits of a four-year cycle with its next electric rate case, as Ms. Duell states on page 15, lines 5 through 11, of her testimony?

A. No. The prudent next step in the evolution of the Company's Line Clearing Program is the outlined five-year line clearing cycle. Once the five-year cycle is attained, the Company will re-evaluate other tactics for continuous improvement in risk management, including cycle considerations.

REBUTTAL OF AG WITNESS COPPOLA

Q. On page 174, line 7, through page 175, line 18, AG witness Coppola supports, in principle, the Company's proposal to defer line clearing expenses above a certain threshold but disagrees with the baseline the Company has chosen. How do you respond?

A. The Company appreciates the Attorney General's support for its proposal in principle, and the Company maintains that its recommended baseline for the test period is reasonable. Company witness Patrick D. Daly addresses Mr. Coppola's recommendation, but I would also like to clarify how the baseline would operate in practice in 2026 in further response to Mr. Coppola's recommendation that the Company defer all line clearing expenses above $110,225,000 beginning in 2026. The amounts in Figure 13 on page 36 of my direct testimony, which shows the Company's baseline expense requirements, were calculated using the Company's current projection for the annual expense required to maintain the five-year line clearing cycle once fully achieved after the 2030–2031 test period as further described in my direct testimony on page 35, lines 1 through 14. These projections were then set to present dollars to reflect each calendar year. This approach assumes that each year is operating under a full five-year cycle. The test period baseline was calculated as 8/12th of 2026 calendar year projected baseline to maintain the five-year clearing cycle (once attained) and 4/12th of 2027 calendar year projected baseline to maintain the five-year clearing cycle (once attained).

However, in practice, calendar year 2026 will be a transitional year in the ramp-up process. Specifically, the first four months of 2026 will still operate under the previous seven-year effective cycle approved in Case No. U-21585, while the remaining

eight months will reflect the ramp up to the new five-year cycle proposed in the present case. As a result, the Company wants to clarify that the baseline operational expense for calendar year 2026 is $150.6 million based on four months (January through April 2026) at the Company's currently approved Forestry spend from Case No. U-21585 plus eight months (May through December 2026) of the five-year line clearing cycle (once attained) projected for 2026. This amount reflects the transitional nature of the year and provides a more representative view than the $163.4 million shown in Figure 13. This includes $138.6 million in LVD expenses.

No clarifications are necessary to the test year baseline expense requirement of $164.5 million, which includes $152.6 million in LVD expenses, as this figure appropriately reflects the adjusted projection for the test period.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. GENSCH: Next is company witness Caitlin M. Tetrick. Ms. Tetrick had direct testimony consisting of a cover page and 10 pages of questions and answers and Ms. Tetrick sponsored Exhibits A-178 and A-179.

THE COURT: Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct testimony of Caitlin Tetrick is bound in the record and Exhibits A-178 and A-179 are admitted.

(At 3:08 p.m., Exhibits A-178 and A-179 are admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U- 21870

DIRECT TESTIMONY

OF

CAITLIN M. TETRICK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Caitlin M. Tetrick, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Total Rewards & Workforce Strategy.

Q. Please describe your educational background and work experience.

A. I graduated in 2011 from Michigan State University with a Bachelor of Arts in Journalism. In addition, I graduated from the University of Michigan's Ross School of Business in 2019 with a Master of Business Administration, and hold a certificate for a Senior Professional from the Society of Human Resources ("HR"). I joined Consumers Energy in 2011, and have held non-supervisory positions in Information Technology, Smart Energy, Customer Communications, and Co-worker Communications. I have also held supervisory positions within our Customer Care department and our HR functions, including supervising internal communications, employee experience, workforce planning, People & Culture strategy, and Total Rewards.

Q. What are your responsibilities as Executive Director of Total Rewards & Workforce Strategy?

A. My responsibility as Executive Director of Total Rewards & Workforce Strategy is to provide direction to five key functions within the People & Culture department, including Strategic Workforce Planning, People & Culture Strategy, Co-worker Communications, Benefits & Compensation, and Co-worker Experience. Of the functions, Strategic Workforce Planning is most relevant to this testimony.

That function is responsible for leading and/or executing strategic workforce planning, human resources, and contracted partner management, including responsibility for headcount planning and optimizing resources.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide support for Consumers Energy's projected capital investments and Operating and Maintenance ("O&M") spending in Low Voltage Distribution ("LVD") and High Voltage Distribution ("HVD") with respect to operational resources.

First, I will discuss Consumers Energy's resource needs. Second, I will discuss the Company's resource planning approach, including use of a cross-functional resource planning review process, the importance of leveraging both Company and contracted resources, and the ability of the Company to adequately use our talent pipeline to ensure resource adequacy.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-178 (CMT-1)	Summary of Historical Year, Bridge Period, and Projected Test Year for Operations Resources – Electric LVD Workplan; and
Exhibit A-179 (CMT -2)	Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources – Electric HVD Workplan.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. How does Consumers Energy plan for the workforce required to deliver the Reliability Roadmap, as presented by Company witness Michael P. Kelly, and how will it meet these resourcing demands?

A. The Company's requirement for its operational workforce is analyzed using a cross-functional resource planning process that focuses on one to five years of future resource needs.

This proactive plan development provides visibility into any resource gaps and adequate time to address those gaps. It also focuses on developing Company resources in a way to provide greater value to the customer by reducing safety risks and developing workforce skills within the Company. These continuously advancing skills are key to the success of the investment work outlined in the Reliability Roadmap, as sponsored by Company witness Kelly as Exhibit A-129 (MPK-19). By executing the plan with a highly trained and safety-minded workforce, the Company will ultimately produce a more reliable and resilient grid.

The Company meets its resourcing demands as follows: first, the Company effectively and efficiently scales its workforce capacity to meet its operational workplans, inclusive of its Utility Workers Union of America ("UWUA") and contract workforces. The Company has demonstrated its ability to scale its workforce capacity from 2019 through 2024. Total apprentices in the Electric Lines Program have grown from 135 in 2019, to 312 in 2024. During that same period, the number of qualified journey line workers in Electric Operations grew from 470 in August 2019, to 550 in December 2024. This growth in the workforce has increased the Company's capacity to deliver work focused on meeting customer needs for a reliable and resilient grid.

Our planning process constantly evaluates the need for workforce capacity adjustments consistent with the Company's efforts to maintain and improve the electric distribution system. Second, direct hiring and apprentice programs play a key and sustainable part in the Company's approach to secure operational resources and must be commensurately scaled and funded.

Q. Please describe the Company's Electric Lines Apprenticeship Program.

A. It takes four years of training and on-the-job experience to train a journey line worker. The length of time required to train a journey line worker means the Company must have a strong, future-facing workforce plan. As apprentices advance in the Company's program, they can apply various new skills, based on where they would fall in the four steps of the apprenticeship program. In Step I of their apprenticeship, they acquire skills in climbing and can work on energized secondary, string power lines between poles, sagging of conductor, and streetlighting. In Step II of their apprenticeship, they acquire the technical ability to test equipment, install transformers, frame and set poles, and build power banks. In Step III of their apprenticeship, they acquire the skills to conduct work on single phase energized primary, protective equipment, and perform switching. During Step IV of their apprenticeship, they acquire the skillset to install line equipment, remove line equipment, work energized primary climbing, and work multi-phase energized primary. As they advance in the apprenticeship program, they acquire the skills to perform the above tasks safely, and with direct oversight from qualified journeymen, in addition to a joint oversite committee partnered between the Company and UWUA. Each subsequent level of apprentice provides a higher level of value to customers as many of them are focused on reliability-based projects that pertain to their specific skill level.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. OVERVIEW OF RESOURCE NEEDS

II. RESOURCING APPROACH

I. OVERVIEW OF RESOURCE NEEDS

Q. What are the Electric Operations resources needed to complete the electric distribution workplan?

A. The Company will need to increase both its LVD and HVD Field Maintenance and Construction resources beyond current levels to complete the electric distribution workplan. The change in operational resource needs are as follows:

	2025	2026	2027
LVD	1,229	1,537	1,742
HVD	504	539	530
Total Resources	1,733	2,076	2,272
Growth Percentage (YOY)		**20%**	**9%**

The projected resources are needed to complete the distribution workplan as described by Company witnesses Andrew R. Snider, Megan L. Hayward, Michael P. Kelly, Scott A. McPhail, Jennifer M. Partlan, and Daniel A. Schmoekel. The costs associated with these resources are sponsored by Company witness Kelly and are summarized in Exhibits A-12 (MPK-1), Schedule B-5.7 and A-125 (MPK-15).

Q. How are the projected resource needs determined in Exhibits A-178 (CMT-1) and A-179 (CMT-2)?

A. Resource needs are determined by reviewing the various work types, applying historical data using reasonable expectations (historic times for completion of specific work types),

and identifying the funding and qualified resource needs required to complete the work plan each year.

II. RESOURCING APPROACH

Q. What is the Company's approach to identifying its resource needs?

A. The Company uses a cross-functional resource planning process that brings visibility to current and future resource needs, and enables the ability to ensure sufficient resources are available at the right times to meet demand. By evaluating future resource requirements, the Company can make sure essential workplans are achievable and plans are in place to fill any identified gaps through appropriate countermeasures.

Resource needs are determined based on the level of investment in programs such as Demand Failures, New Business, Reliability, Capacity, and Asset Relocation. These resource needs are translated into work hours needed to support the entire workplan. When gaps are identified, the planning team works together to identify countermeasures and prioritize the workplan. Employee safety, customer experience, and efficient use of resources are each part of the balanced approach that drives the mix of countermeasures selected.

Longer-term choices, such as adding apprentices, are the result of long-term work plan projections, and improve our capability to deliver in the future as demands increase, such as those outlined in the Reliability Roadmap.

The Company is taking proactive measures to significantly increase its capability to execute the Reliability Roadmap. These measures include direct hiring and apprenticeships as well as contractor networks, each with an emphasis on building scalable and effective local workforces. Various skilled resources are needed for Electric

Operations, including LVD line workers, HVD line workers, electric underground line workers, electric field lab employees, substation operators and maintenance personnel, and grid management personnel. The Company is exploring alternative resourcing strategies that enable resources to be deployed quickly. First, in December of 2024, the Company began direct hiring of qualified Journey Line Workers. Overall efforts were positive, resulting in hiring 20 qualified workers as part of the effort. Recruiting efforts for 2026 resources will begin in the fall of 2025 to ensure resources can be onboarded for the test year of the case. To enhance recruitment efforts, the Company plans to engage with a search firm to identify qualified Journey Line Workers seeking a career move. Marketing materials will be updated to highlight the benefits of working at Consumers Energy. Social media and radio advertising will be used as well. Secondly, the Company intends to fill some of the necessary positions by re-skilling J.H. Campbell plant employees. Currently, 70 positions, from Basic Line Apprentices to Underground Line Workers, are being held to re-deploy resources to support this initiative as the Company transitions away from coal-fired generation and executes upon its Integrated Resource Plan that was approved in Case No. U-21090.

Securing the workforce needed to do this work is a vital part of the Company's ability to achieve the improved reliability that the Reliability Roadmap is meant to deliver. The Company intends to secure the additional labor resources needed to achieve the plan and will continue to move toward these increased workforce goals, but it must have certainty of long-term support for this plan.

A. LVD Maintenance and Construction

Q. How many LVD workers does the Company currently utilize?

A. As of December 31, 2024, the Company uses 1,017 full-time Consumers Energy LVD field workers to complete LVD maintenance and construction work. In addition, the Company has divided the state into four zones with contracts competitively bid and awarded to provide contractor support for each zone. Furthermore, the four zone contractors and numerous additional contractors may participate in specific bids or provide resources for ongoing workload, where additional resources are needed for specific project work or to balance internal crewing capacity.

Q. How many LVD workers does the Company anticipate needing for the projected test year?

A. The Company anticipates needing 1,742 workers to complete the work in the projected test year as shown in Exhibit A-178 (CMT-1), which provides an overview of the Company's operational resource needs for the LVD workplan.

Contractor resources will flex up or down to complement the work being performed by our internal crews. Contractor resources may also be flexed up or down based on the nature of the work being performed or based on the availability of our crews relative to the total workplan.

Q. How does the Company determine the number of resources that are needed to complete distribution workplans?

A. Workforce needs are determined by historical workplans, projected capital and O&M, and estimated attrition levels.

Q. How does the Company build and maintain the LVD and Underground workforces required to complete the planned distribution work?

A. The Company negotiated contractual agreements with the UWUA in 2020 to hire 72 apprentices in 2023, and 72 apprentices in 2024. The hiring of additional apprentices aligned with current attrition rates and projected workplans to build a correctly sized LVD workforce. This yielded hiring of 348 Journey Line Worker Apprentices between 2021-2024. The Company is direct-hiring skilled LVD workers, as well as using apprenticeship programs with community colleges, a Veterans Hiring Program, and the UWUA. The Company has expanded its work with additional community colleges, allowing an extended reach into communities, targeting increased diversity and a long-term reduction of internal transfers by virtue of initially hiring employees into the regions they want to live in long term.

Specifically, the Company initiated partnerships with strategic community colleges located across Michigan including Jackson, Flint, Alpena, and Lansing in 2008 to host line worker pre-apprenticeship programs. These programs, like the School to Work ("STW") Program, provide skilled trade training opportunities. The STW Program has yielded great success as 74% of the Company's apprentice line worker hires have come through the program since 2014.

B. HVD Maintenance and Construction

Q. What workforce does the Company utilize to perform HVD line work?

A. The Company uses a contractor workforce to complete HVD line maintenance, construction, and restoration via a competitive bidding process. In addition, the primary

HVD contractors and numerous additional contractors may participate in specific bids for more complex HVD project work.

The Company works closely with its primary HVD contractors to ensure awareness and visibility into the workplan to ensure cost effectiveness, stability, and growth of the HVD workforce as needed to support the plan. HVD line contractors are only approved to work on the HVD side of lines, with the exception of restoration activities, where LVD restoration is needed.

Q. What workforce does the Company utilize to perform HVD substation work?

A. The level of complexity of HVD substation work, along with the optimized planned use of resources, drives the decision making for which workforce to use for substation work. Maintenance work, emergent repairs, and short-cycle planned work are often completed by Company employees in the HVD Substation Maintenance group. A competitive bid process is used for engaging dedicated resources or part-time contractors for influxes of work or within planned specific projects.

Q. What are the Company's HVD workforce needs for the projected test year?

A. Exhibit A-179 (CMT-2) provides an overview of the Company's operational resource needs for the HVD workplan.

Q. Does this complete your direct testimony?

A. Yes.

MR. GENSCH: Thank you, Your Honor.

And then lastly is a company witness, Brian J. VanBlarcum. Mr. VanBlarcum had direct testimony consisting of a cover page and eight pages of questions and answers. He also had rebuttal testimony consisting of a cover page and five pages of questions and answers and Mr. VanBlarcum sponsored Exhibits A-180, A-181, A- 228, and A-229.

THE COURT: Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct and rebuttal testimony of Brian VanBlarcum is bound into the record and Exhibits A-180, A-181, A-228, and A-229, are admitted.

(At 3:09 p.m., Exhibits A-180, A-181, A-228, and A-229, are admitted).

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

DIRECT TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Brian J. VanBlarcum, and my address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am a Tax Director in the Company's Corporate Tax Department.

Q. Please briefly describe your educational background.

A. I am a graduate of Western Michigan University where I earned a Bachelor of Business Administration degree in Finance.

Q. Please describe your business experience.

A. I started with the Company in 2004 as a General Accounting Analyst with the Company's property accounting team. In 2019, I was appointed to my current position as Tax Director with the Company's Corporate Tax Department.

Q. Are you a certified assessor?

A. I am a Michigan Certified Assessing Officer certified by the State of Michigan's State Tax Commission and a member of the Michigan Assessors Association.

Q. What are your responsibilities as Tax Director?

A. I am responsible for the administration of the Company's real and personal property taxes. This includes: (i) managing the Company's self-declaration of personal property located within the state of Michigan; (ii) overseeing property tax matters concerning the Company's land, generating sites, and other real property; and (iii) supervising tax payments to approximately 1,500 taxing authorities. I am also responsible for the

calculation of federal and state tax depreciation related to the Company's fixed assets and the associated deferred income taxes.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I sponsored testimony in the following cases:

- Gas Rate Case No. U-15506;
- Electric Rate Case No. U-15645;
- Electric Rate Case No. U-16191;
- Gas Rate Case No. U-16418;
- Electric Rate Case No. U-17087;
- Electric Rate Case No. U-17735;
- Gas Rate Case No. U-17882;
- Electric Rate Case No. U-17990;
- Gas Rate Case No. U-18124;
- Electric Rate Case No. U-18322;
- Gas Rate Case No. U-18424;
- Electric Rate Case No. U-20134;
- Gas Rate Case No. U-20322;
- Gas Rate Case No. U-20650;
- Electric Rate Case No. U-20697;
- Gas Rate Case No. U-21148;
- Electric Rate Case No. U-21224;
- Electric Rate Case No. U-21389;

- Gas Rate Case No. U-21490;
- Electric Rate Case No. U-21585; and
- Gas Rate Case No. U-21806.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony identifies the Property Tax Rate for the test year (12 months ending April 30, 2027) and explains how the rate was derived. I am also supporting the amount of test year excess deferred federal income taxes being returned to electric customers as a result of the Tax Cuts and Jobs Act of 2017 ("TCJA") and the Commission's September 26, 2019 Order in the Company's Calculation C proceeding, Case No. U-20309.

Q. Have you prepared any exhibits to accompany your direct testimony?

A. Yes. I am sponsoring:

Exhibit A-180 (BJV-1)	Development of the Property Tax Rate for the Test Year; and
Exhibit A-181 (BJV-2)	Amortization of Excess Deferred Federal Income Taxes for the Test Year and Tax Reform Regulatory Liability & Amortization.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

<u>Development of the Property Tax Rate for the Test Year</u>

Q. What is the Property Tax Rate for the test year?

A. As indicated on Exhibit A-180 (BJV-1), page 1, line 18, the Property Tax Rate for the test year is 0.013349387.

Q. How did you calculate the Property Tax Rate for the test year?

A. The Property Tax Rate for the electric business was calculated using the Company's prorated Electric Property Tax Expense, shown on Exhibit A-180 (BJV-1), page 1, line 11,

divided by the total of the 2026 Estimated Year-End Plant-in-Service, shown on Exhibit A-180 (BJV-1), page 1, line 12, plus one-half of the 2026 Estimated Construction Work-in-Progress, shown on Exhibit A-180 (BJV-1), page 1, line 15.

Q. What is included in the Electric Property Taxes Paid – 2026 Estimate on Exhibit A-180 (BJV-1), page 1, line 1?

A. The 2026 taxes paid by Consumers Energy of $281.9 million on behalf of the electric portion of the business represents the estimated property taxes to be paid in 2026.

Q. What is included in the Electric Property Taxes on 2026 Plant Investment on Exhibit A-180 (BJV-1), page 1, line 2?

A. The $33.6 million increase is the estimated property taxes on the 2026 net additions that will be included in the 2027 property tax liability. This is calculated by taking the capital additions, less retirements, times the first year State Tax Commission multiplier table value to recognize a depreciation allowance, which is then multiplied by the statutory reduction of 50% of true cash value to get the assessed value, then multiplied by Consumers Energy's composite millage rate of 49.7863 to obtain the estimated tax amount. This calculation is shown on Exhibit A-180 (BJV-1), page 2, line 9.

Q. What is included in the 2027 Fossil Plant Valuation Tax Reduction on Exhibit A-180 (BJV-1), page 1, line 3?

A. The $0.1 million decrease reflects a reduction in property taxes associated with the D.E. Karn Plant (Units 3-4). The reduction in property taxes is the result of successful negotiations with the local unit of government over the taxable value of the Company's fossil fuel-fired electric generating facilities.

Q. What is included in the Electric Property Taxes on Real Property Taxable Value Increases on Exhibit A-180 (BJV-1), page 1, line 4?

A. The $1.2 million increase for the Real Property Taxable Value relates to the Michigan Constitution of 1963, Article IX, Section 3, allowing local assessors to raise real property taxable values by the lesser of 5% or the Consumer Price Index ("CPI"). For 2027, the Company's property tax model assumes a CPI rate of 2.4%. This calculation is shown on Exhibit A-180 (BJV-1), page 3.

Q. What is the result of including the Electric Property Taxes on 2026 Plant Investment, 2027 Fossil Plant Valuation Tax Reduction, and Electric Property Taxes on Real Property Taxable Value Increase on the estimated 2027 property tax amount paid by the electric business?

A. The result of including these additional items is an estimated 2027 property tax amount to be paid for the electric business of $316.6 million, as shown on Exhibit A-180 (BJV-1), page 1, line 5.

Q. Does the amount on Exhibit A-180 (BJV-1), page 1, line 6, include property tax payments for pollution control equipment or computer software, such as SAP?

A. No, as pollution control equipment and computer software are exempt under MCL 324.5904(1) and MCL 211.9d, the estimate of 2027 property tax to be paid on line 6 does not include property taxes associated with these items.

Q. How is this paid amount converted to an expense amount?

A. Since the Company expenses property taxes based on the fiscal year of the taxing authorities, 50.0% of the 2026 estimated electric property tax payments for Consumers Energy is added to the 2027 estimated electric payments since that amount will be expensed

in 2027, while subtracting 50.0% of the 2027 estimated electric payments that will be expensed in 2028, arriving at a total 2027 electric property tax expense of $299.3 million as shown on Exhibit A-180 (BJV-1), page 1, line 8.

Q. What is the next step in calculating the tax rate for the test year?

A. For the test year, property tax expense was prorated for the period of May 1, 2026 through April 30, 2027 using a monthly budgeted sales percentage applied to the 2026 and 2027 estimated annual property tax expense amounts. The result of factoring property tax expense monthly for the test period is a prorated Electric Property Tax Expense of $280.5 million, as shown on Exhibit A-180 (BJV-1), page 1, line 11. The prorated Electric Property Tax Expense for the test year is divided by the 2026 Estimated Year-End Plant-in-Service plus one-half of 2026 Estimated Construction Work-in-Progress to arrive at a property tax rate of 0.013349387.

Q. On March 21, 2025, in Case No. U-21585, the Commission supported the Administrative Law Judge's recommendation that, "Consumers continue to provide a list of pending tax assessment litigation cases and negotiations in rate case filings going forward." Does the Company have any current property tax litigation?

A. No. The Company is not currently involved in property tax litigation at this time.

<u>Amortization of Excess Deferred Federal Income Taxes for the Test Year</u>

Q. On September 26, 2019, in Case No. U-20309, the Commission issued an Order in the Company's Calculation C case. What specific issues did the September 26, 2019 Order address?

A. The Commission's September 26, 2019 Order in the Company's Calculation C case authorized the amount and time period under which the Company will refund to electric

customers $1,174,181,000 of excess deferred federal income taxes as a result of the TCJA lowering the corporate income tax rate from 35% to 21%. As part of the settlement terms in Case No. U-21224, the Commission approved an adjustment to reduce this amount by $4,168,278 to correct an overstatement of the TCJA remeasurement. The Commission authorized three different amortization periods: (i) Protected plant balances over an amortization period determined using the Average Rate Assumption Method ("ARAM"); (ii) Non-Protected plant balances amortized over 27 years; and (iii) Unprotected non-plant balances amortized over 10 years. Exhibit A-181 (BJV-2), page 2, referenced as Exhibit A-5 (SBM-3) in Case No. U-20309, provides the projected annual amortization of these balances based on the periods approved by the Commission.

Q. What additional amount of excess deferred taxes related to the TCJA has the Company proposed to refund to customers in this case?

A. As shown on Exhibit A-181 (BJV-2), page 1, line 22, the Company has proposed to refund an additional $7,907,000 of excess deferred taxes ($10,604,000 of regulatory liability after gross-up for taxes) in this case. This amount represents the Company's regulatory liability recorded as of year-end 2022 which was calculated as the difference between the actual amount of excess deferred taxes for the year and the estimated amount included in rates. The Company's most recently filed report to the Case No. U-20309 docket, which calculates the $10,604,000 regulatory liability balance, is included as Exhibit A-181 (BJV-2), page 3.

Q. Based on the Commission's September 26, 2019 Order in Case No. U-20309 and the additional amount described above, what amount of excess deferred federal income tax has the Company proposed to return to customers in this case?

A. Exhibit A-181 (BJV-2), page 1, provides a calculation of the test year excess deferred federal income taxes included in this case based on the periods approved by the Commission in Case No. U-20309. Overall, the Company reduced Federal Income Tax Expense for the test year by $40.434 million to reflect the amortization periods and amounts discussed above. This amount is shown on Company witness Patrick D. Daly's Exhibit A-13 (PDD-45), Schedule C-8, lines 45, 46, and 47 as TCJA Tracker, TCJA Amortization – ARAM and TCJA – Non-ARAM.

Q. Are the excess deferred federal income tax amounts refunded to electric customers in the test year estimates or actuals?

A. The amounts included in this case are estimates as the Commission's September 26, 2019 Order in Case No. U-20309 requires an annual reconciliation of the actual amount of excess deferred federal income tax in a given year and the estimated amount included in rates. The Company will file this reconciliation in Case No. U-20309 by March 31st of each year.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Brian J. VanBlarcum, and my business address is One Energy Plaza, Jackson, MI 49201.

Q. Are you the same Brian J. VanBlarcum who previously submitted testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Attorney General witness Sebastian Coppola to increase the amount of accrued taxes included in working capital by $30 million, which reduces working capital by the same amount.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-228 (BJV-3)	Workpaper WP-PDD-29; and
Exhibit A-229 (BJV-4)	Workpaper WP-PDD-36.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. What amount of accrued taxes did Consumers Energy Company ("Consumers Energy" or the "Company") forecast to be included in working capital for the projected test year?

A. As shown in Company witness Patrick D. Daly's Exhibit A-12 (PDD-34), Schedule B-4, line 15, column (p), the Company projected accrued taxes of $256.080 million. The Company utilized the 13-month average from December 2024, which was $286.120 million as shown on Exhibit A-12 (PDD-34), Schedule B-4, line 15, column (d), and made

a downward accrued tax adjustment of $30.040 million, as shown on Exhibit A-12 (PDD-34), Schedule B-4, line 15, column h.

Q. Why is the Company's $30.040 million downward adjustment necessary?

A. The $286.120 million, 13-month average as of December 2024, includes Federal, State, and Local income taxes accrued for the 2023 and 2024 tax years. This balance is not reflective of accrued taxes related to the projected test period May 1, 2026 through April 30, 2027. Since accrued income taxes included in the December 2024, 13-month average will be settled prior to the projected test year, it is appropriate to remove the settled amount from the December 2024, 13-month average and replace that amount with a projection of Federal, State, and Local income taxes related to the projected test period.

Accrued taxes, which are included as a component of working capital in rate base, are calculated on taxable income derived from both pre-tax book income and timing differences that generate deferred income taxes. Deferred income taxes are a zero-cost component of the capital structure.

Sound ratemaking requires that there is synchronization between the capital structure and rate base. Since additional deferred income taxes, including those created by timing differences for projected book and tax depreciation, are included in the capital structure, and accrued taxes are included in rate base, the Company's adjustment to accrued taxes ensures that these two components are adjusted in unison. To the extent that the Company projects additional deferred taxes included in the capital structure for this case but fails to recognize the corresponding change in accrued taxes or rate base, this disconnection has the effect of immediately reducing rates and providing a tax benefit to customers. The failure to recognize this disconnection and providing such an unintended

tax benefit to customers has the effect of causing a normalization violation under the Internal Revenue Code. The consistency rules required by the Internal Revenue Code require four components to remain in synchronization: (1) depreciation expense; (2) tax expense; (3) reserve for deferred taxes; and (4) rate base. As outlined above, the Company's adjustment to accrued taxes as a component of working capital in rate base would ensure compliance with Section 168(i)(9)(B) of the Internal Revenue Code.

Q. On pages 105 and 106 of his direct testimony, Attorney General witness Coppola presented his adjustment to the Company's projection of accrued taxes. What specific adjustment did Mr. Coppola recommend?

A. In his direct testimony, Attorney General witness Coppola recommends that accrued taxes for the test year be set at $286.1 million, the Company's historical, 13-month average balance for the period ending December 2024, increasing the Company's projection of accrued taxes by $30.0 million and reducing working capital by the same $30.0 million.

Q. Please explain why Attorney General witness Coppola's accrued tax and working capital adjustment is incorrect.

A. Attorney General witness Coppola's recommendation to use the historical accrued tax balance of $286.1 million, the 13-month average balance as of December 2024, is incorrect as that balance includes accrued income taxes related to prior tax years which are not related to the projected test year. Further, Attorney General witness Coppola's recommendation to set accrued taxes at the actual 13-month average as of December 2024 fails to take into consideration any taxable income projection or timing differences related to the projected test year. Consideration of these items is imperative because book and tax timing differences, especially those related to book depreciation and tax depreciation,

require equal consideration when adjusting accrued income taxes derived from current tax expense and deferred income taxes derived from deferred income tax expense. As noted earlier, it is incorrect to adjust one side of this equation without equal consideration for both current and deferred income tax expense and the impact of accrued income taxes included as a component of rate base and deferred income taxes included in the capital structure.

Q. On page 105, line 11, of his direct testimony, Attorney General witness Coppola references the Company's discovery response U21870-AG-CE-0459, which acknowledged accrued taxes for the test year do not include additional income from rate relief requested in this case, claiming the Company's assumption of no new rate relief is unrealistic and its calculation of accrued taxes is seriously flawed. Did the Company calculate an appropriate amount of accrued taxes based on Federal, State, and Local taxable income projections relative to the projected test year?

A. Yes. The details supporting the Company's $30.0 million adjustment can be found on Exhibit A-228 (BJV-3), Company witness Daly's workpaper, WP-PDD-29, which removes the previously mentioned Federal, State, and Local accrued income taxes unrelated to the projected test period and adds back a 13-month average based on Federal, State, and Local income tax projections reflective of the projected test period. The Company's 13-month accrued income tax balance, based on assumptions from the test period, is shown on Exhibit A-229 (BJV-4), Company witness Daly's workpaper, WP-PDD-36.

Q. Do you agree that such an adjustment for rate relief should be made?

A. No. Attorney General witness Coppola's assertion that requested rate relief should be included in the calculation of accrued taxes included in rate base is contrary to the long standing and consistent methodology used in prior cases. In fact, no other working capital items are adjusted to reflect requested rate relief. If such an adjustment were made for income tax liabilities included in working capital, other assets included in working capital, such as accrued revenue or accounts receivable, would also need to be increased for rate relief offsetting the increase to income tax liabilities.

Q. Does this conclude your rebuttal testimony?

A. Yes.

THE COURT: I take it that's it as far as binding in on behalf of the company, is that correct?

MR. GENSCH: Yes, Your Honor.

THE COURT: All right, I see it's 3:09. We're going to take a 10 minute break. We're off the record.

(At 3:09 p.m., off the record)

(At 3:20 p.m., on the record)

THE COURT: We're back on the record. Sara, are you with us?

THE COURT REPORTER: Yes, I am.

THE COURT: Thank you. Would you do the honors of binding in for Urban Core Collective?

MR. TEMPLETON: Well, thank you, Your Honor. It's Mark Templeton for Urban Core Collective. I'm going to bind in the testimony and move for the admission of the exhibits of our two witnesses and two exhibits that are in lieu of cross-examination of certain Consumer's witnesses. So our first witness was Sergio Cira-Reyes, he had direct written testimony consisting of one cover page and 95 pages of questions and answers. In that direct written testimony, he sponsored Exhibits UCC-1 through UCC-97, that's 97 inclusive and he had no rebuttal testimony, so at this time I would move to bind in Mr. Cira-Reyes direct written testimony and move for the admission of that UCC-1 through UCC-97 inclusive.

THE COURT: Are there any objections to the

admission of this testimony or these exhibits?

Hearing none, the direct testimony of Sergio Cira-Reyes is bound in the record and Exhibits UCC-1 through UCC-97 are admitted.

(At 3:22 p.m. Exhibits UCC-1 through UCC-97 are admitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for generation and distribution of electricity and for other relief.	U-21870 ALJ Jonathan F. Thoits

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DIRECT TESTIMONY OF SERGIO CIRA-REYES

ON BEHALF OF

URBAN CORE COLLECTIVE

September 30, 2025

I. INTRODUCTION AND SUMMARY OF QUALIFICATIONS

Q: Please state your name, occupation, and business address.

A: My name is Sergio Cira-Reyes, and I serve as the Climate Justice Catalyst at Urban Core Collective ("UCC"), a non-profit organization based at 413 Hall St. SE #1, Grand Rapids, Michigan, 49507.

Q: Have you participated in any previous MPSC proceedings?

A: Yes, I provided (1) testimony in Consumers Energy's Integrated Resource Plan ("IRP") case U-21090 (2) testimony in Consumers Energy's rate application case U-21224, (3) testimony in Consumers Energy's Voluntary Green Pricing ("VGP") case U-21374, (4) testimony in DTE Gas Company's rate application case U-21291, (5) testimony in Consumers Energy's rate application case U-21389, and (6) testimony in Consumers Energy's rate application case U-21585. I also led the development of UCC's strategy and positions regarding the settlement in those cases.

Q: Please describe your education and work experience.

A: I lived in Los Angeles until I was twenty, when I transferred from community college to Calvin College in Grand Rapids, Michigan, to study psychology and social work from 2000 to 2002. After this, I worked simultaneously at a residential treatment facility for minors and as a part-time translator for the courts. In 2010, I started work as a school social worker and for a local organization called West Side Collaborative in Grand Rapids. I have worked for UCC for the past several years, first as the Director of

Community Engagement and now in my current role as Climate Justice Catalyst, in which I lead the organization's environmental justice efforts.

My approximately two decades of experience in both direct service roles and systems change work allow me to understand the challenges faced by low-income communities and communities of color, as well as the systems that limit their opportunities.

Q: What is the Urban Core Collective?

A: UCC is a 501(c)(3) organization founded in 2014 by six organizations based in western Michigan. The six original organizations joined forces to pursue the common goal of overcoming the effects of systemic racism by promoting equal access to education, economic prosperity, health, power, and influence.[1] During my time at UCC, I have worked with these organizations and their constituents by facilitating multiple public meetings for a former UCC member organization, the Hispanic Center of Western Michigan; by participating in panels for our Transformational Leadership Programs; and by participating in the interview and selection process for this program for employees of our member organizations, among other activities.

Q: Can you provide examples of the types of work UCC does related to climate, energy, and the environment?

A: In 2019, UCC partnered with the City of Grand Rapids to carry out the Zero Cities Project sponsored by the U.S. Sustainability Directors Network. This project sought to

[1] Ex. UCC-1, *About*, URB. CORE COLLECTIVE (last visited Aug. 26, 2025), https://perma.cc/47GW-KX9L, at 1.

develop a roadmap towards a net-zero building sector by 2050. UCC's role involved engaging residents on policy options, educating the public on the utility industry, and serving as an equity consultant on policy design.[2] UCC also conducted a consumer survey on residential energy services, receiving approximately 120 responses from residents who were primarily renters, low-income, or African American.[3] This survey helped to identify residents' knowledge of various energy services related to energy efficiency and financial assistance.[4]

In 2019, UCC and a group of City of Grand Rapids staff, community leaders, issues experts, and environmental justice advocates formed the Community Collaboration on Climate Change ("C4") to develop a plan for climate justice in Grand Rapids.[5] UCC's priority as a member of C4 is to ensure equity is a central component of the group's work.

In July 2022, UCC obtained a grant to conduct more community organizing and improve voter access. We have hired two new team members dedicated to this work, and we have tasked them with highlighting energy issues—such as those in this case—when working on voter engagement. We also have implemented methods to use climate justice as a mechanism for voter turnout. As a result of this improved voter turnout, we have seen increased climate messaging by political candidates.

UCC intervened in Consumers Energy's IRP case No. U-21090 and partnered with Empower Michigan—a coalition of Michigan organizations that worked together to

[2] Ex. UCC-2, C4, ZERO CITIES PROJECT & HEZERO: MPSC EWR – LI MEETING (2021), at 11; *see also* Ex. UCC-3, C4 PLANNING TEAM, COMMUNITY COLLABORATION ON CLIMATE CHANGE (C4) (2021), at 10.
[3] Ex. UCC-2 at 42.
[4] *Id.* at 43.
[5] *Id.* at 4.

increase public participation in the IRP process before the Michigan Public Service Commission ("MPSC" or "Commission"). UCC held a public meeting on September 20, 2021, in southeast Grand Rapids—in a zip code where the population is approximately 30% Black and approximately 30% Latino—to provide information to attendees about the IRP process. We discussed how the Commission works and informed members of the public of opportunities they had to present their opinions to the Commission. UCC signed the IRP settlement in U-21090. Of particular importance to UCC were the settlement agreement's provisions related to the establishment of a fund to assist low-income customers and communities; data gathering improvements related to environmental and energy justice; and increased engagement with the public regarding utility planning.[6]

UCC also supports leaders of color in the environmental space by creating affinity groups for persons of color to get outdoors and to discuss environmental issues relevant to them.

Finally, as described further below, UCC has intervened in this case to help ensure that any authorized rate change accounts for the input and needs of low-income and Back, Indigenous, and People of Color ("BIPOC") communities in Western Michigan.

I am knowledgeable about these activities and have participated in them as UCC's lead staffer on environmental and energy issues. Working so closely with community members has allowed me to understand the broad range of challenges they face and how energy intersects with these challenges and concerns.

[6] *In re Consumers Energy Co.*, MPSC Case No. U-21090, MPSC Order (June 23, 2022), Ex. A at 11–12, 13–16.

Q: How else does UCC advocate for community members' interests?

A: Outside of UCC's climate work, UCC has also worked on community engagement, education justice, democratic participation, and public safety in Grand Rapids. For instance, UCC convened a workgroup made up of residents, neighborhood association representatives, City of Grand Rapids officials and employees, and members of the clergy to design a framework for how the City of Grand Rapids should engage with the public when there are new development projects. As part of this project, UCC conducted in-person meetings in Spanish and English and conducted multiple surveys. In education justice, UCC is working with the Grand Rapids Public Schools as process monitors and is auditing their strategic planning process. UCC is helping to inform their engagement process to ensure that members of the public—including advocates and impacted communities—can elevate their voices and shape outcomes. UCC's democratic participation work focuses on increasing voter registration and raising awareness of voting procedures. UCC's work in public safety has involved hosting multiple meetings with stakeholders in the community who are interested in holding our local police department accountable and developing strategies to empower residents to take ownership of their own safety. Finally, UCC has leadership development programs for emerging leaders both within the community and within our organization.

In sum, UCC's expertise lies in explaining complex institutions and systems of power to local communities and in gathering input about how these institutions and

systems can better address community needs. Through this work, UCC can be an effective advocate for meaningful change and institutional accountability.

Q: Why did UCC intervene in this case?

A: UCC intervened in this case regarding issues that affect low-income and BIPOC communities disproportionally: reliability, affordability, and engagement in the ratemaking process.

As I will establish in the following sections of this testimony, low-income and BIPOC communities already face high energy burdens relative to the rest of the population, with energy burdens defined as the share of a household's income that goes toward their energy bills. These households' energy burdens are often exacerbated by living in energy-inefficient housing stock and lower rates of participation in distributed energy resources such as solar power, which could save them money over time on their utility bills. To make matters worse, historically they have suffered higher rates of exposure to the pollution byproducts of electricity generation. Low-income households also experience disproportionate economic and health effects when the distribution side of the electric grid fails during power outages. Putting these different inequities together, with a particular focus on affordability in the instant case, my testimony will discuss how Consumers can improve service provision outcomes for these communities while increasing transparency and public participation in decision-making.

Q: Please provide an overview of the topics you will discuss in your testimony.

A: In Part II, I will discuss the background of the concerns of low-income and BIPOC communities that are relevant to the issues at stake in this proceeding. I will then discuss the inadequacy of measures to protect these communities from rate increases and unaffordable energy bills.

In Part III, I will discuss the Company's investments in reliability. The Company has proposed meaningful incremental investments in EJ communities, but it should invest more quickly than it is proposing in this case.

In Part IV, I will question the Company's proposal to increase the Investment Recovery Mechanism due to cost overruns and before the Commission has had an opportunity to review fully the Company's expenditures to date.

In Part V, while noting progress that the Company has made, I will discuss the need for additional support for and investments in environmental justice communities, including DER investments.

In Part VI, I will discuss the Company's community engagement, including how the Company should partner with more environmental justice organizations in engaging with the communities those organizations serve.

In Part VII, I will discuss concerns with the Company's proposed recovery for corporate membership fees that do not benefit ratepayers.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits.

UCC-1. *About*, URB. CORE COLLECTIVE (last visited Aug. 26, 2025), https://perma.cc/47GW-KX9L.

UCC-2. C4, ZERO CITIES PROJECT & HEZERO: MPSC EWR – LI MEETING (2021).

UCC-3. C4 PLANNING TEAM, COMMUNITY COLLABORATION ON CLIMATE CHANGE (C4) (2021).

UCC-4. Ross Beall & Carolyn Hronis, *In 2020, 27% of U.S. Households Had Difficulty Meeting Their Energy Needs*, U.S. ENERGY INFO. ADMIN. (Apr. 11, 2022), https://perma.cc/4QNQ-JDWD.

UCC-5. APPLIED PUB. POL'Y RSCH. INST. FOR STUDY AND EVALUATION (APPRISE), RATEPAYER-FUNDED LOW-INCOME ENERGY PROGRAMS: PERFORMANCE AND POSSIBILITIES (2007).

UCC-6. AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY (ACEEE), DATA UPDATE: CITY ENERGY BURDENS (2024) (available at https://perma.cc/QDF2-4N6J).

UCC-7. *Study: One in Four Low-Income Households Spend Over 15% of Income on Energy Bills*, AMER. COUNCIL FOR AN ENERGY-EFFICIENT ECON. (Sep. 11, 2024), https://perma.cc/Z4QK-J7EB.

UCC-8. MARK WOLFE ET AL., CTR. FOR ENERGY POVERTY AND CLIMATE (CEPC), AMERICA NEEDS A PARADIGM SHIFT IN HOW THE NATION RESPONDS TO EXTREME HEAT (2024) (available at https://perma.cc/V8ME-6DTN).

UCC-9. U-21870 Public Case Comments.

UCC-10. Sonal Jessel et al., *Energy, Poverty, and Health in Climate Change: A Comprehensive Review of the Emerging Literature,* 7 FRONTIERS IN PUB. HEALTH Art. 357 (2019).

UCC-11. Sanya Carley et al., *Behavioral and Financial Coping Strategies Among Energy-Insecure Households*, PROC. OF THE NAT'L ACAD. OF SCIS. OF THE U.S. (2022).

UCC-12. Ross Beall & Carolyn Hronis, *U.S. Energy Insecure Households Were Billed More for Energy than Other Households*, U.S. ENERGY INFO. ADMIN. (May 30, 2023), https://perma.cc/FLG8-WB8A.

UCC-13. Kyle Ross & Justin Dorazio, *The Latest Poverty, Income, and Food Insecurity Data Reveal Continuing Racial Disparities*, CTR. FOR AM. PROGRESS (Dec. 21, 2022), https://www.americanprogress.org/article/the-latest-poverty-income-and-food-insecurity-data-reveal-continuing-racial-disparities/.

UCC-14. KRYSTAL JONES ET AL., MICH. CTR. FOR DATA AND ANALYTICS, 2024 MICHIGAN ECONOMIC ANALYSIS REPORT (2025) (available at https://perma.cc/BNJ3-QHLV).

UCC-15. *Living in the Cold: Addressing the Inequalities of Heating Energy Poverty in the Winter*, ENERGY INNOVATION (Oct. 18, 2013), https://energyinnovation.org/expert-voice/living-in-the-cold-addressing-the-inequalities-of-heating-energy-poverty-in-winter/.

UCC-16. Laura M. Tach & Sara S. Greene, *"Robbing Peter to Pay Paul":* Economic *and Cultural Explanations for How Lower-Income Families Manage Debt*, 61 SOC. PROBS. 1 (2014).

UCC-17. NAT'L ENERGY ASSISTANCE DIRS.' ASS'N (NEADA), 2011 NATIONAL ENERGY ASSISTANCE SURVEY FINAL REPORT (2011).

UCC-18. NEADA, 2018 NATIONAL ENERGY ASSISTANCE SURVEY FINAL REPORT (2018).

UCC-19. Tony G. Reames et al., *Exploring the Nexus of Energy Burden, Social Capital, and Environmental Quality in Shaping Health in US Counties*, 18 INT'L J. OF ENV'T RSCH. & PUB. HEALTH 620 (2021).

UCC-20. Soojin Han et al., *Energy Burden and Mental Health: A National Study in the United States*, 955 SCI. OF THE TOTAL ENV'T 176796 (2024).

UCC-21. Diana Hernández, *Understanding 'Energy Insecurity' and Why It Matters to Health*, 167 SOC. SCI. & MED. 1 (2016).

UCC-22. *Energy Burden Research*, ACEEE, https://perma.cc/EBL5-WKTG (last visited Sep. 19, 2025).

UCC-23. *Extreme Weather and Climate Change*, NASA, https://perma.cc/KS4S-7S33 (last visited Sep. 19, 2025).

UCC-24. Jaqueline M. Doremus et al., *Sweating the Energy Bill: Extreme Weather, Poor Households, and the Energy Spending Gap*, 112 J. OF ENV'T ECON. AND MGMT. Art. 102609 (2022).

UCC-25. CTR. FOR ENERGY POVERTY AND CLIMATE AND NAT'L ENERGY ASSISTANCE DIRS.' ASS'N, CRISIS IN ENERGY AFFORDABILITY): SUMMER SHUTOFF PROTECTIONS AND BILL SUPPORT FAIL TO ADAPT TO A WARMING WORLD (2024) (available at https://perma.cc/H5JW-YWMV).

UCC-26. Jacqueline E. Cardoza et al., *Heat-Related Illness Is Associated with Lack of Air Conditioning and Pre-existing Health Problems in Detroit, Michigan, USA: A Community-Based Participatory Co-Analysis of Survey Data*, INT'L J. OF ENV'T RSCH. & PUB. HEALTH (Aug. 7, 2020).

UCC-27. Assistant Secretary for Health, *Extreme Heat,* U.S. DEP'T OF HEALTH AND HUM. SERVS. (July 2, 2024).

UCC-28. ARIEL DREHOBL ET. AL, AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON., HOW HIGH ARE HOUSEHOLD ENERGY BURDENS? (2020)

UCC-29. Luis Ortiz et al., *Energy Burden and Air Conditioning Adoption in New York City Under a Warming Climate*, 76 SUSTAINABLE CITIES AND SOC'Y Art. 103465 (2022).

UCC-30. Image taken from: Sanya Carley & David Konisky, *Utility Connections Dashboard*, ENERGY JUST. LAB (2023), https://utilitydisconnections.org/dashboard/index.html (screenshot captured Sep. 22, 2025).

UCC-31. SELAH G. BELL ET AL., CTR. FOR BIOLOGICAL DIVERSITY, POWERLESS IN THE U.S. (2023) (available at https://perma.cc/4X2E-66ME).

UCC-32. Micki Olson & Jeannete Sutton, *Bridging the Gap Between National Weather Service Heat Terminology and Public Understanding*, AM. METEOROLOGICAL SOC'Y (2025).

UCC-33. *Understanding Heat Alerts*, NAT'L WEATHER SERV., https://perma.cc/M6BN-SHKX (last visited Sep. 10, 2025).

UCC-34. AMY BANDYK ET AL., U-20140 COMMENT FROM ENERGY EQUITY GROUPS (2025).

UCC-35. STATE OF MICH. DEP'T OF TREASURY, INFLATION RATE MULTIPLIER FOR USE IN THE 2025 CAPPED VALUE FORMULA AND THE "HEADLEE" MILAGE REDUCTION FRACTION (MRF) FORMULA (2024) (available at https://perma.cc/DZA2-GJZL).

UCC-36. SCR Workpaper 1.

UCC-37. 2024 UTILITY OUTAGES, MICH. PUB. SERV. COMM'N (2025) (available at https://perma.cc/7DWM-MLT8).

UCC-38. CONSUMERS ENERGY CO., CONSUMERS ENERGY PIPP PILOT PROGRAM (PERCENTAGE OF INCOME PAYMENT PLAN) (2025).

UCC-39. Consumer Energy Company's Response to UCC's First Discovery Request, U21870-UCC-CE-0239.

UCC-40. Consumer Energy Company's Response to UCC's Second Discovery Request, U21870-UCC-CE-0376.

UCC-41. *Federal Poverty Level (FPL)*, HEALTHCARE, https://perma.cc/MP2J-V89A (last visited Sep. 21, 2025).

UCC-42. Consumer Energy Company's Response to UCC's First Discovery Request, U21870-UCC-CE-0234.

UCC-43. Consumer Energy Company's Response to UCC's First Discovery Request, U21870-UCC-CE-0233_Byrom_ATT_1.

UCC-44. Consumer Energy Company's Response to UCC's Second Discovery Request, U21870-UCC-CE-0369.

UCC-45. Consumers Energy Company's Response to UCC's First Discovery Request, U21870-UCC-CE-0237.

UCC-46. MICH. ENV'T COUNCIL, NAT. RES. DEF. COUNCIL, CITIZENS UTIL. BD. OF MICH. ECOLOGY CTR. AND VOTE SOLAR, U-21021 COMMENTS ON DTE ELECTRIC COMPANY AND DTE GAS COMPANY AND CONSUMERS ENERGY COMPANY PIPP PILOTS (2025).

UCC-47. Consumers' Response UCC's Third Discovery Request, U21870-UCC-CE-0685.

UCC-48. MICHAEL E. MOODY & CHRISTOPHER BZDOK, MICH. DEP'T OF ATT'Y GEN. & CITIZENS UTIL. BD. OF MICH., U-20929 & U-21021 COMMENTS ON APPLICATIONS OF DTE GAS COMPANY., DTE ELECTRIC COMPANY AND CONSUMER ENERGY COMPANY FOR APPROVAL OF PIP PILOT PROGRAM (2025).

UCC-49. Joan A. Casey et al., *Power Outages and Community Health: A Narrative Review*, 7 CURRENT ENV'T HEALTH REPS. 371 (2020).

UCC-50. Patrick Madamba, *How Do Power Outages Affect Households?*, U.S. CENSUS BUREAU (Oct. 2, 2024), https://perma.cc/FNR5-VW8K.

UCC-51. Consumers Electric's Response to UCC's First Discovery Request, U21870-UCC-CE-0233.

UCC-52. Consumers Electric's Response to UCC's First Discovery Request, U21870-UCC-CE-0233_Byrom_ATT_2.

UCC-53. Consumers Electric's Response to UCC's First Discovery Request, U21870-UCC-CE-0233_Byrom_ATT_3.

UCC-54. Consumers Electric's Response to UCC's Second Discovery Request, U21870-UCC-CE-0368.

UCC-55. Juan Declet-Barreto & Andrew A. Rosenberg, *Environmental Justice and Power Plant Emissions in the Regional Greenhouse Gas Initiative States*, 17 PLOS ONE 1 (2022).

UCC-56. Dept. of Environment, Great Lakes, and Energy, *MiEJScreen: Environmental Justice Screening Tool (Version 1.0)*, MICHIGAN.GOV, https://perma.cc/U865-JXTL (last visited Sep. 21, 2025).

UCC-57. *MIEJ SAIDI and SAIFI Viewer*, EXPERIENCE.ARCGIS.COM, https://perma.cc/M5CN-XJF6 (last visited Sep. 21, 2025).

UCC-58. *Solar Integration: Distributed Energy Resources and Microgrids,* U.S. DEP'T OF ENERGY (2025), https://perma.cc/8RN4-5D5W (last visited Sep. 21, 2025).

UCC-59. *Sharing the Sun Market Report Details Expansive Growth, Recent Trends in Community Solar,* NAT'L RENEWABLE ENERGY LAB'Y (Oct. 19, 2021), https://perma.cc/2FHV-QUNG.

UCC-60. *Solar Gardens*, CONSUMERS ENERGY, https://perma.cc/HS9T-RH3A (last visited Sep. 18, 2025).

UCC-61. KATY WAECHTER ET AL., NAT'L RENEWABLE ENERGY LAB'Y, TECHNICAL POTENTIAL AND MEANINGFUL BENEFITS OF COMMUNITY SOLAR IN THE UNITED STATES (2024).

UCC-62. ERIC SIPPERT, ENV'T L. AND POL'Y CTR., COMMUNITY-OWNED COMMUNITY SOLAR – OPPORTUNITIES AND CHALLENGES (2022) (available at https://perma.cc/EE3D-QLRQ).

UCC-63. *Community Solar Basics*, U.S. DEP'T OF ENERGY, https://perma.cc/F8MG-FP6T (last visited Sep. 21, 2025).

UCC-64. KATIE KIENBAUM ET AL., INST. FOR LOC. SELF-RELIANCE, ADVANTAGE LOCAL: WHY LOCAL ENERGY OWNERSHIP MATTERS (2023).

UCC-65. Lee Samelson, *The Difference Between Community Engagement and Marketing*, CMTY. POWER (Feb. 16, 2016), https://www.communitypowermn.org/the_difference_between_community_engagement_and_marketing.

UCC-66. LaTorria Sims et al., *Community Engagement: A Cornerstone of Environmental Justice*, RAMBOLL (Sep. 17, 2024), https://perma.cc/T96V-ZD3T.

UCC-67. Humberto Queiroz et al., *Understanding User Engagement and Needs in Energy Communities*, 2024 INT'L CONF. ON ENG'G, TECH., AND INNOVATION (2024).

UCC-68. Consumers Electric's Response to UCC's First Discovery Request, U21870-UCC-CE-0236_ATT_1.

UCC-69. Consumers Electric's Response to UCC's Third Discovery Request, U21870-UCC-CE-0688.

UCC-70. Consumers Electric's Response to UCC's First Discovery Request, U21870-UCC-CE-0236.

UCC-71. SCR Workpaper 2.

UCC-72. *Issues & Policy: Reliability, Resilience & Emergency Response*, EDISON ELEC. INST., https://perma.cc/NNX9-SR9V (last visited Sep. 3, 2025).

UCC-73. EDISON ELEC. INST., 2025 LOBBYING, ADVOCACY, AND OTHER EXPENDITURES (2025) (available at https://perma.cc/5A77-MJRR).

UCC-74. EDISON ELEC. INST., IRS FORM 990 (2023).

UCC-75. *About EEI*, EDISON ELEC. INST., https://perma.cc/2VQ8-38DN (last visited Sep. 21, 2025).

UCC-76. *About MEGA*, MEGA, https://perma.cc/8D6P-9WHR (last visited Sep. 3, 2025).

UCC-77. *Mission*, MICH. CHAMBER OF COMMERCE, https://perma.cc/PZ78-RTX8 (last visited Sep. 3, 2025).

UCC-78. EDISON ELEC. INST., NEW PUBLIC POWER TAKEOVERS: STRATEGIC RESOURCES FOR DEFEATING MUNICIPALIZATION (2002) (available at https://perma.cc/3ZFT-QYK9).

UCC-79. Gabe Elsner, *Utilities' Anti-Solar Campaign and Misinformation Debunked*, ENERGY AND POL'Y INST. (Mar. 19, 2015), https://perma.cc/C9LS-4EFE.

UCC-80. Joby Warrick, *Utilities Wage Campaign Against Rooftop Solar*, THE WASH. POST (Mar. 7, 2015), https://perma.cc/AS54-MTZZ.

UCC-81. William Pentland, *Disruptive Deceptions: How Electric Utilities Stifled Rooftop Solar*, FORBES (Dec. 4, 2015), https://perma.cc/35BG-JMCV.

UCC-82. Hiroko Tabuchi, *Rooftop Solar Dims Under Pressure from Utility Lobbyists*, N.Y. TIMES (July 28, 2017), https://perma.cc/C3Q8-PHB7.

UCC-83. David Pomerantz, *EEI Used Anti-Clean Energy Campaigns as Role Models in Political Boot Camp for Utility Execs*, ENERGY & POL'Y INST. (Aug. 27, 2020), https://perma.cc/8VYB-CU2Y.

UCC-84. Emily L. Williams et al., *The American Electric Utility Industry's Role in Promoting Climate Denial, Doubt, and Delay*, 17 ENV'T RSCH. LETTERS Art. 094026 (2022).

UCC-85. Kim Riley, *EEI Takes Targeted Strike at EPA's Power Plant Emissions Rule*, DAILY ENERGY INSIDER (May 22, 2024), https://perma.cc/JYK3-LZS4.

UCC-86. Matt Kasper, *Coal and Utility Interests Ask for, Receive, Bailouts to Help Failing Power Plants*, ENERGY & POL'Y INST. (Oct. 2, 2017), https://perma.cc/K38V-64YL.

UCC-87. Gavin Bade, *FERC Seeks Fast Track on DOE Baseload Compensation Proposal*, UTIL. DIVE (Oct. 2, 2017), https://perma.cc/9ER9-QEMX.

UCC-88. Dave Anderson, *Ohio's Big Utilities Fight Repeal of Scandal-Tainted Bill Riders that Cost Customers Billions of Dollars*, ENERGY & POL'Y INST. (Mar. 24, 2025), https://perma.cc/B5J7-8HMC.

UCC-89. SEC Release Nos. 33-11042 and 34-94478, File No. S7-10-22 (June 17, 2022).

UCC-90. *Scope 3 Inventory Guidance*, EPA, https://perma.cc/LZ5C-ZHHQ (last visited Sep. 21, 2025).

UCC-91. ENERGY & POL'Y INST., PAYING FOR UTILITY POLITICS: HOW RATEPAYERS ARE FORCED TO FUND THE EDISON ELECTRIC INSTITUTE AND OTHER POLITICAL ORGANIZATIONS (2017) (available at https://perma.cc/8TGM-2XG6).

UCC-92. *In re Evergy Missouri West, Inc.*, Missouri PSC Case No. ER-2024-0189, Giacone Direct Testimony (June 27, 2024) (excerpted).

UCC-93. *In re Kentucky Utilities Co.*, Case No. 2020-00349, Order (June 30, 2021) (excerpted).

UCC-94. *In re Avista Utilities*, PUC Docket No. UG 461, Order No. 23-384 (Oct. 26, 2023) (excerpted).

UCC-95. *In re Arizona Public Service Co.*, ACC Docket No. E-0135A-22-0144, Order (Mar. 5, 2024) (excerpted).

UCC-96. Christian Roselund, *California Prevents Utility from Paying EEI Dues with Ratepayer Funds*, PV MAGAZINE (May 21, 2019), https://perma.cc/U26J-WVAP.

UCC-97. Mark Jaffe, *Xcel Ordered to Remove Investor Relations and Executive Salaries from Costs Passed on to Colorado Consumers*, THE COLO. SUN (Nov. 5, 2024), https://perma.cc/C86P-FP6J.

II. ENERGY AFFORDABILITY

Q: How does the Commission define affordability?

A: The Commission defines energy affordability as "the extent to which a household has the resources to meet their home energy needs for heating, cooling and other uses in a healthy, sustainable, and energy efficient manner without compromising a household's ability to meet other basic needs."[7] The Commission's definition recognizes that affordability is not just about the monthly cost of energy, but also about the ability of households to pay for utility services while still meeting other essential needs like food,

[7] *In re Response to COVID-19*, MPSC Case No. U-20757, Order (Dec. 21, 2023), at 36.

housing, healthcare, and transportation. It also emphasizes the importance of energy efficiency and sustainability in promoting long-term affordability.

Q: What is "energy insecurity," and how is it different from "energy burden"?

A: Energy challenges can be defined in two related ways: energy insecurity and energy burden.

A household is *energy insecure* when its members are unable to meet their basic energy needs, such as having challenges paying their energy bills or keeping their home at a safe temperature.[8] Across the United States, 27% of U.S. households have reported instances of energy insecurity, such as not being able to pay their energy bills or keeping their homes at unsafe temperatures, according to the U.S. Energy Information Administration.[9]

Meanwhile, a household's *energy burden* is defined as the percentage of the household's budget spent on energy bills. An energy burden of 6%—that is, spending 6% or less of one's income on energy costs, including both natural gas and electricity—is generally considered affordable.[10] While the median energy burden for all U.S. households is estimated to be around 2.9%,[11] "25% of all low-income households in the United States have an energy burden above 15.2%."[12]

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[8] *See* Ex. UCC-4, Ross Beall & Carolyn Hronis, *In 2020, 27% of U.S. Households Had Difficulty Meeting Their Energy Needs*, U.S. ENERGY INFO. ADMIN. (Apr. 11, 2022), https://perma.cc/4QNQ-JDWD, at 1.

[9] *Id.*

[10] Ex. UCC-5, APPLIED PUB. POL'Y RSCH. INST. FOR STUDY AND EVALUATION (APPRISE), RATEPAYER-FUNDED LOW-INCOME ENERGY PROGRAMS: PERFORMANCE AND POSSIBILITIES (2007), at 8.

[11] Ex. UCC-6, AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY (ACEEE), DATA UPDATE: CITY ENERGY BURDENS (2024) (available at https://perma.cc/QDF2-4N6J), at 8.

[12] *Id.* at 1.

Q: In general, is energy affordability a challenge for and a concern of low- and moderate- income (LMI) communities?

A: LMI households often face greater energy burdens relative to higher-income households, leading to disproportionate economic and health impacts.[13] As I will discuss in further detail below, when energy costs take up an increasing share of a household's budget, it forces households to make difficult trade-offs.[14] I have seen this in my own community, with households having to choose among paying bills on time, keeping houses at healthy temperatures, and paying for basic necessities, such as food or medicine. For example, one Consumers' customer posted about this struggle in a public comment in the present rate case:

> As someone on a fixed income . . . I have to set the thermostat to an uncomfortable temperature in both the summer and winter in an attempt to keep my bill in a range that I can pay every month . . . I avoid using my electric stove, or my electric clothes dryer also. I only ta[k]e cool showers twice a week so my water heater doesn't run. Nobody with a disability should have to live like this . . . Do you sit in the dark in the evenings to avoid turning on your lights?[15]

According to recent U.S. Census Bureau Household Pulse Survey data, 51% of households earning less than $50,000 per year report foregoing basic necessities for at least a month each year to be able to afford energy bills and prevent shutoffs.[16]

[13] Ex. UCC-7, *Study: One in Four Low-Income Households Spend Over 15% of Income on Energy Bills*, AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON. (Sep. 11, 2024), https://perma.cc/Z4QK-J7EB, at 2.
[14] Ex. UCC-8, MARK WOLFE ET AL., CTR. FOR ENERGY POVERTY AND CLIMATE (CEPC), AMERICA NEEDS A PARADIGM SHIFT IN HOW THE NATION RESPONDS TO EXTREME HEAT (2024) (available at https://perma.cc/V8ME-6DTN), at 3.
[15] Ex. UCC-9, U-21870 Public Case Comments, at 10.
[16] Ex. UCC-8 at 3.

The energy burden is significant for LMI households, including in Consumers Energy Company's ("Consumers" or "the Company") territory and elsewhere in Michigan. As stated above, the median energy burden for all U.S. households is estimated to be around 2.9%, whereas the energy burden for low-income households is nearly three times as large at 8.3%.[17] Furthermore, a quarter of low-income households experience an energy burden at or above 15.2%.[18] Consumers identifies 11% of their customers as "in crisis and unable to pay their energy bill" and another 26% of their customers "as being one crisis away from being able to pay their energy bill."[19]

Energy bills are more expensive per square foot in energy-insecure households.[20] Energy-insecure households generally have homes that are less insulated and are not weatherized. Additionally, they often have older appliances that are less energy-efficient and lack funds for repairs and upgrades.[21] Consequently, energy-insecure households often pay more for energy usage than the average household. In 2020, U.S. households were billed an average of $1.04 per square foot for all energy usage. However, energy-insecure households were billed $0.20 more than the national average and $0.26 more than energy-secure households per square foot.[22]

[17] Ex. UCC-6 at 8.
[18] *Id*. at 3.
[19] Byrom Direct Testimony at 27–28.
[20] Ex. UCC-10, Sonal Jessel et al., *Energy, Poverty, and Health in Climate Change: A Comprehensive Review of the Emerging Literature,* 7 FRONTIERS IN PUB. HEALTH Art. 357 (2019), at 8–9.
[21] *Id*. Households that suffer from deficient housing conditions, such as mold, poor insulation, broken air conditioning, or broken appliances, are more likely to undertake multiple coping strategies. *See generally* Ex. UCC-11, Sanya Carley et al., *Behavioral and Financial Coping Strategies Among Energy-Insecure Households*, PROC. OF THE NAT'L ACAD. OF SCIS. OF THE U.S. (2022).
[22] Ex. UCC-12, Ross Beall & Carolyn Hronis, *U.S. Energy Insecure Households Were Billed More for Energy than Other Households*, U.S. ENERGY INFO. ADMIN. (May 30, 2023), https://perma.cc/FLG8-WB8A, at 2.

Q: Are energy insecurity and energy affordability concerns of the Black, Indigenous, and People of Color (BIPOC) communities with which you work?

A: Energy insecurity and energy affordability also challenge many BIPOC communities and households.

First, while not exclusively the case, BIPOC households typically comprise a higher percentage of LMI communities than of non-LMI communities.[23] Thus many BIPOC households experience the same challenges as LMI households.

Second, economic statistics indicate that unemployment is higher for Black workers than White workers, which affects the ability of these populations to afford energy and other household necessities. In Michigan, the unemployment rate among Black workers in 2024 was 7.6% while the unemployment rate among White workers was 4%.[24] At 3.6 percentage points, the unemployment rate gap between White and Black workers in Michigan was 50% higher in 2024 than it was in 2023.[25]

Third, BIPOC communities often have less energy-inefficient housing.[26] BIPOC households, on average, pay more for energy per square foot than the U.S. average. Data from 2020 shows that Black households were billed, on average, $1.21 per square foot and Hispanic/Latino households were billed $1.16 per square foot, while White households were billed at $1.02 per square foot.[27]

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[23] *See generally* Ex. UCC-13, Kyle Ross & Justin Dorazio, *The Latest Poverty, Income, and Food Insecurity Data Reveal Continuing Racial Disparities*, CTR. FOR AM. PROGRESS (Dec. 21, 2022), https://www.americanprogress.org/article/the-latest-poverty-income-and-food-insecurity-data-reveal-continuing-racial-disparities/; *see also* Ex. UCC-7.

[24] Ex. UCC-14, KRYSTAL JONES ET AL., MICH. CTR. FOR DATA AND ANALYTICS, MICHIGAN ECONOMIC ANALYSIS REPORT (2024) (available at https://perma.cc/BNJ3-QHLV), at 3.

[25] *Id*.

[26] Ex. UCC-6 at 2.

[27] Ex. UCC-12 at 2.

Fourth, BIPOC households, on average, have higher energy burdens than the national average.[28] Data about the upper quartile of energy burdens in twenty-five major U.S. urban areas showed that all Black households in that quartile had an energy burden of 7.2%, all Hispanic households 6.2%, and all households 5.7%; the figures were 7.8%, 6.8%, and 6.3% for renters, respectively.[29]

For these reasons, many of the impacts of energy insecurity and energy affordability that I will discuss about LMI households and communities below to many BIPOC households and communities as well.

Q: Can you please provide more detail about how energy insecurity and a lack of affordable energy impact LMI households?

A: Energy insecurity and a lack of energy affordability often lead to rationing of electricity[30] and other necessities.[31] LMI customers often keep their homes at an unsafe temperature or forego other necessities like food or medicine to keep their lights on.[32]

To illustrate this issue, I have included Table 1, which reflects survey data for 2011 and 2018 regarding non-energy costs of unaffordable energy bills from the National Energy Assistance Directors Association. [33] The surveyed households received Low

[28] Ex. UCC-6 at 2.
[29] *Id.* at 3 tbl.1. For low-income households, the figures for all households were 15.2% and 13.2% for renters. *Id.*
[30] Ex. UCC-15, *Living in the Cold: Addressing the Inequalities of Heating Energy Poverty in the Winter*, ENERGY INNOVATION (Oct. 18, 2013), https://energyinnovation.org/expert-voice/living-in-the-cold-addressing-the-inequalities-of-heating-energy-poverty-in-winter/, at 5.
[31] Ex. UCC-16, Laura M. Tach & Sara S. Greene, *"Robbing Peter to Pay Paul": Economic and Cultural Explanations for How Lower-Income Families Manage Debt*, 61 SOC. PROBS. 1 (2014), at 1, 9–12.
[32] Ex. UCC-15 at 5; *see also In re DTE Electric Co.*, MPSC Case No. U-21534, Makhijani Direct Testimony (July 26, 2024), at 6 TR 4584, lines 1–7.
[33] *See generally* Ex. UCC-17, NAT'L ENERGY ASSISTANCE DIRS.' ASS'N (NEADA), 2011 NATIONAL ENERGY ASSISTANCE SURVEY FINAL REPORT (2011); *see also* Ex. UCC-18, NEADA, 2018 NATIONAL ENERGY ASSISTANCE SURVEY FINAL REPORT (2018).

Income Home Energy Assistance Program (LIHEAP) assistance at least one time in the five-year period preceding the year of the survey.

Table 1: Non-energy costs of unaffordable energy bills among LIHEAP-assistance recipients[34]

Impacts	% in 2011*	% in 2018	Comments
Kept home at unsafe temperature*	23%	25%	Increases ill-health among the vulnerable, such as older people
Used stove or oven to provide heat*	33%	30%	Increases indoor air pollution
Had electricity or natural gas cut-off*	11%	15%	Cut-off of electricity can result in violation of rental contracts and the threat of eviction
Lost home and moved in with friends or family**	2.8%	3.4%	Potential crowding and other negative social consequences
Lost home and became unhoused and moved to shelter**	0.8%	1.2%	Decline in life-expectancy if homelessness becomes chronic; increase in shelter costs to taxpayers, increase in health costs to hospitals
Did not fill prescription fully**	6.8%	6.2%	
Went without medical or dental care**	7.4%	8.2%	
Went without food for at least one day**	5.8%	7.2%	

Note: * indicates information from prior year; ** indicates information from the annual average of the five years prior to the survey.

As a result, households with high energy burdens are more likely to suffer from poor health outcomes. U.S. counties that experience higher energy burdens are associated

[34] *In re DTE Electric Co.*, MPSC Case No. U-21534, Makhijani Direct Testimony (July 26, 2024), at 6 TR 4584, lines 1–7.

with experiencing higher rates of premature death, fair or poor self-reported health, and lower life expectancy—"each unit of increase in LMI energy burden is associated with an average 240 more premature deaths per 100,000 people between 2016 and 2018."[35] Furthermore, a higher energy burden is positively correlated with higher levels of physician-diagnosed depression and frequent mental distress.[36]

Energy insecurity can also lead to poor health outcomes. A lack of safe temperatures inside one's home can trigger asthma symptoms and respiratory diseases, especially during the winter months.[37] The challenges caused by energy insecurity, such as having to worry about paying the bills or the poor conditions of one's home, can trigger mental health disorders, such as depression and anxiety. This forces some people to seek out a medical provider for mental health treatment.[38] The health consequences of energy insecurity and high energy burdens offer further compelling reasons to advance energy affordability.

Although there are some assistance programs to aid with financial challenges, the available programs are often difficult to access and insufficient to meet current needs, so households are likely to participate in risky coping behaviors instead of or in addition to participating in government energy assistance programs.[39] The demand for bill assistance

[35] Ex. UCC-19, Tony G. Reames et al., *Exploring the Nexus of Energy Burden, Social Capital, and Environmental Quality in Shaping Health in US Counties*, 18 INT'L J. OF ENV'T RSCH. & PUB. HEALTH 620 (2021), at 7.
[36] Ex. UCC-20, Soojin Han et al., *Energy Burden and Mental Health: A National Study in the United States*, 955 SCI. OF THE TOTAL ENV'T 176796 (2024), at 7.
[37] Ex. UCC-21, Diana Hernández, *Understanding 'Energy Insecurity' and Why It Matters to Health*, 167 SOC. SCI. & MED. 1 (2016), at 7; *see also* Ex. UCC-22, *Energy Burden Research*, ACEEE, https://perma.cc/EBL5-WKTG (last visited Sep. 19, 2025), at 1.
[38] Ex. UCC-21 at 7.
[39] Ex. UCC-8 at 3.

outpaces the outreach efforts and funds from the government to reach energy-insecure households.[40]

While these data are national, there is reason to believe that these trends hold for households in Michigan, as well as in Consumers' service territory. For example, as stated in the testimony of Justin Schott, Director of the Energy Equity Project and Lecturer at the University of Michigan School for Environment and Sustainability, in MPSC Case U-21291, according to Pulse Survey Data conducted biweekly by the U.S. Census since the start of COVID-19, between February 6 and March 4, 2024, 33.2% of Michigan households reported some frequency of foregoing other basic needs (including 49.0% of Hispanic and 46.7% of Black households), 19.9% reported keeping the home at an unsafe or uncomfortable temperature, and 25.8% reported being unable to pay the energy bill in full."[41]

Each of the coping mechanisms used by LMI households to prevent shutoffs poses health and safety risks and decreases residents' quality of life.

Q. How do extreme weather events exacerbate these challenges in LMI communities?

A: The pattern of low-income residents keeping their homes at unsafe temperatures to prevent shutoffs is especially concerning given the rise of climate change-induced extreme weather events.[42] For example, during episodes of extreme heat, many LMI households are forgoing appropriate cooling measures because of the high costs of

[40] Ex. UCC-11 at 7.
[41] *In re DTE Gas Co.*, MPSC Case No. U-21291, Schott Direct Testimony (May 7, 2024), at 4 TR 1082 (citing to Justin Schott, JS FLO Working Paper 2).
[42] *See generally* Ex. UCC-23, *Extreme Weather and Climate Change*, NASA, https://perma.cc/KS4S-7S33 (last visited Sep. 19, 2025).

running air conditioners.[43] In my own community, I have seen people choose to spend much of their time at the mall or other air-conditioned public spaces to avoid using energy at home. A recent U.S. Census Bureau Household Pulse Survey found that in 2024, 20.3% of residents reported keeping their homes at a "temperature that felt unsafe or unhealthy, at least one month in the last year," and 30.9% of households having an annual income of less than $50,000 reported the same.[44]

Prohibitive cooling costs have dangerous consequences, including more frequent emergency room visits, deteriorated mental health, decreased learning, and death. A study conducted in the Detroit metro area underscores these dangerous consequences, finding that a lack of air conditioning can lead to a variety of health problems, including cramps, heat exhaustion, heatstroke, hyperthermia, respiratory problems, and even death.[45] According to the U.S. Department of Health and Human Services, heat-related deaths in the U.S. have been rising, increasing from approximately 1,602 in 2021 to 2,302 in 2023.[46] The summers of 2023 and 2024 were the hottest summers ever recorded on Earth and that trend is projected to continue.[47] Burdensome energy costs will

[43] *See* Ex. UCC-24, Jaqueline M. Doremus et al., *Sweating the Energy Bill: Extreme Weather, Poor Households, and the Energy Spending Gap*, 112 J. OF ENV'T ECON. AND MGMT. Art. 102609 (2022), at 12.
[44] Ex. UCC-25, CTR. FOR ENERGY POVERTY AND CLIMATE AND NAT'L ENERGY ASSISTANCE DIRS.' ASS'N, CRISIS IN ENERGY AFFORDABILITY: SUMMER SHUTOFF PROTECTIONS AND BILL SUPPORT FAIL TO ADAPT TO A WARMING WORLD (2024) (available at https://perma.cc/H5JW-YWMV), at 3.
[45] Ex. UCC-26, Jacqueline E. Cardoza et al., *Heat-Related Illness Is Associated with Lack of Air Conditioning and Pre-existing Health Problems in Detroit, Michigan, USA: A Community-Based Participatory Co-Analysis of Survey Data*, INT'L J. OF ENV'T RSCH. & PUB. HEALTH (Aug. 7, 2020), at 1, 8.
[46] Ex. UCC-27, Assistant Secretary for Health, *Extreme Heat,* U.S. DEP'T OF HEALTH AND HUM. SERVS. (July 2, 2024), at 3.
[47] Ex. UCC-8 at 3.

increasingly force Michigan residents to endure unsafe indoor temperatures to avoid power shutoffs, producing life-threatening consequences.

Since energy-insecure households are often less energy efficient, an LMI household may cool its home less in a hot summer than their wealthier counterpart and still face a higher energy bill per square foot.[48] A New York City-based study found that locations with lower income households had the highest energy burdens from AC use.[49] The authors of the study explain, "Although low-income neighborhoods experience the longest exposure time to indoor extreme heat, they also see the highest relative costs of AC operation."[50] Low-income residents are forced to bear the dual burden of increased exposure to unsafe indoor temperatures as well as the highest costs for cooling interventions.

Statewide, Michigan had around 870,000 disconnections between the months of May and October in 2010 through 2024 inclusive.[51] Of note, Michigan was fourth amongst all states for disconnections, particularly in June,[52] just before periods of extreme heat struck the state. I am concerned about the impact of these disconnections on households just when they need to be able to cool their homes so that they can live in them safely.

[48] Ex. UCC-28, ARIEL DREHOBL ET. AL, AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON., HOW HIGH ARE HOUSEHOLD ENERGY BURDENS? (2020), at 13.
[49] Ex. UCC-29, Luis Ortiz et al., *Energy Burden and Air Conditioning Adoption in New York City Under a Warming Climate*, 76 SUSTAINABLE CITIES AND SOC'Y Art. 103465 (2022), at 33.
[50] *Id.* at 29.
[51] *See generally* Ex. UCC-30, Image taken from: Sanya Carley & David Konisky, *Utility Connections Dashboard*, ENERGY JUST. LAB (2023), https://utilitydisconnections.org/dashboard/index.html (screenshot captured Sep. 22, 2025).
[52] Ex. UCC-31, SELAH G. BELL ET AL., CTR. FOR BIOLOGICAL DIVERSITY, POWERLESS IN THE U.S. (2023) (available at https://perma.cc/4X2E-66ME), at 7.

I appreciate that the Commission has opened a separate docket in Case No. U-20140 for discussion of extreme weather disconnection policies. Joining Soulardarity and We Want Green, Too as members of the Frontline Energy Transition Partners, UCC filed a comment in that docket.[53] Based on our survey of the extreme weather policies of seventeen jurisdictions, we made the following recommendations.[54] First, utilities should be prohibited from disconnecting residential service when either: (1) the forecasted temperature will reach 90°F or above, or (2) the NWS issues a heat advisory, excessive heat watch, or excessive heat warning for the service area, which considers a variety of factors, including an elevated heat index and local preparedness.[55] Additionally, disconnections should be restricted at least 24 hours prior to and after extreme heat events, and these restrictions should be extended to weekends and holidays. UCC also joined a comment arguing for no disconnections during hot summer months.[56]

Given that extreme heat is a pressing health concern, I urge the Commission to order utilities to adopt more protective measures quickly, including forbidding disconnections during hot summer months. But if the extreme heat policy docket in Case No. U-20140 is not going to yield a policy by next summer, the Commission should create a more protective and comprehensive interim heat extreme weather policy for

[53] *In re MPSC Regarding Extreme Weather Condition Policies Filed in Compliance with Michigan Administrative Code R 460.134.,* MPSC Case No. U-20140, Comments of Soulardarity, Urban Core Collective, and We Want Green, Too (Sep. 18, 2025).
[54] *Id.* at 12–13.
[55] *See generally* Ex. UCC-32, Micki Olson & Jeannete Sutton, *Bridging the Gap Between National Weather Service Heat Terminology and Public Understanding*, AM. METEOROLOGICAL SOC'Y (2025); *see also* Ex. UCC-33, *Understanding Heat Alerts*, NAT'L WEATHER SERV., https://perma.cc/M6BN-SHKX (last visited Sep. 10, 2025).
[56] Ex. UCC-34, AMY BANDYK ET AL., U-20140 COMMENT FROM ENERGY EQUITY GROUPS (2025), at 2.

Consumers in the present case that ensures time- and weather-advisory protections that extend past the date of an extreme heat event.[57]

Q: By how much, on average, is Consumers proposing to increase rates for residential customers in this case?

A: The Company projects an average monthly bill increase from $132 to $146, an 11% increase, for residential customers as part of its proposed revenue requirement.[58] This requested increase is more than double the 4.5% residential rate increase that the Commission approved in the most recent rate case (U-21585).[59]

Q: Why are you concerned about Consumers' proposed rate increase?

A: Residential customers, particularly LMI households, already struggle with paying their energy bills. This requested rate increase is likely to exacerbate shutoffs and disconnections by making rates more unaffordable at a time when economic conditions are difficult and deteriorating.

Customers are already having difficulty paying their bills. For example, in December 2024, Consumers disconnected 5,599 residential electric customers for non-

[57] *In re MPSC*, MPSC Case No. U-20140, Comments of Soulardarity, Urban Core Collective, and We Want Green, Too (Sep. 18, 2025), at 11-14.
[58] Connolly Direct Testimony at 9, lines 17–18.
[59] Myers Direct Testimony at 4, lines 22–23.

payment.[60] This represents a more than 15% increase in shutoffs compared to December 2023.[61]

Challenging economic conditions will not make it any easier for Consumers' residential customers to pay for this increase. For example, in 2024, Michigan saw a steep rise in unemployment, placing the Michigan unemployment rate among the highest in the United States.[62] Also, the average hourly wage in Michigan increased by 4.5% from December 2023 to December 2024,[63] so Michigan residents, especially LMI and BIPOC communities, will suffer worsening energy insecurity with the 11% increase in rates Consumers has proposed, especially considering the rise of prices elsewhere in the Michigan economy.[64]

I am troubled that Consumers is asking customers to pay more for service that is of lower quality on some dimensions than that of similar electricity providers. For example, from January 1, 2024, through August 27, 2024, Consumers had more than one million total outages, about 31% more than DTE Electric Company ("DTE").[65] Initial reports for 2025, covering January 1 through July 24, indicate that Consumers had almost

[60] *In re Response to COVID-19 Pandemic*, MPSC Case No. U-20757, Consumers Energy Company's December 2024 Report on Disconnected Service to Occupied and Unoccupied Residences (Jan. 13, 2025) [hereinafter U-20757 Consumer Energy Company's December 2024 Report on Disconnected Service], at 2.

[61] *In re Response to COVID-19 Pandemic*, MPSC Case No. U-20757, Consumer's Energy Company December 2023 Report on Disconnected Service to Occupied and Unoccupied Residences (Jan. 10, 2024) at 2.

[62] Ex. UCC-14 at 3.

[63] Ex. UCC-14 at 17.

[64] Michigan experienced 3.1% inflation from fiscal year 2023 to fiscal year 2024. Ex. UCC-35, STATE OF MICH. DEP'T OF TREASURY, INFLATION RATE MULTIPLIER FOR USE IN THE 2025 CAPPED VALUE FORMULA AND THE "HEADLEE" MILAGE REDUCTION FRACTION (MRF) FORMULA (2024) (available at https://perma.cc/DZA2-GJZL), at 2.

[65] Ex. UCC-36, SCR Workpaper 1; *see* Ex.UCC-37, 2024 UTILITY OUTAGES, MICH. PUB. SERV. COMM'N (2024) (available at https://perma.cc/7DWM-MLT8), at 1.

five times more outages than DTE.[66] While I recognize that addressing reliability concerns requires investments, at the same time, I have to note my concern that the Company is asking ratepayers to pay more for service that has more outages as compared to another leading Michigan utility, at least by this measure.

Q: Does the current set of bill assistance programs sufficiently address the energy burdens experienced by residential customers in Consumers' territory?

A: No. Consumers utilizes three main assistance programs for qualifying customers: the Consumers Affordable Resource for Energy ("CARE") Program, the Residential Income Assistance ("RIA") credit, and the Low-Income Assistance ("LIA") credit.[67] While these programs provide valuable assistance individually and collectively to some households, they are insufficient to fully address concerns about energy insecurity and energy burden.

CARE Flat Rate: The State's Michigan Energy Assistance Program ("MEAP") funds the CARE Flat Rate program, which Consumers is phasing out and replacing with CARE Modified Budget (CARE MB).[68] CARE Flat Rate provides participants with either (1) one-time bill assistance, or (2) enrollment in a twenty-four-month payment plan with fixed, reduced energy bills and forgiveness of up to $4,000 of arrears.[69] The program also offered household efficiency upgrades at no extra cost.[70] The Company

[66] *Id*.
[67] Meyers Direct Testimony at 17, lines 20–23.
[68] Byrom Direct Testimony at 24, lines 20–23; Ex. UCC-38, CONSUMERS ENERGY CO., CONSUMERS ENERGY PIPP PILOT PROGRAM (PERCENTAGE OF INCOME PAYMENT PLAN) (2025), at 31 (filed in *In re Consumers Energy Co.*, MPSC Case No. U-21021, Consumers Energy Company's Percentage of Income Payment Plan Pilot Program Report (May 1, 2025), at 31).
[69] Byrom Direct Testimony at 24, 39 n.4.
[70] *Id*. at 39 n.4.

offered the program to households between 20% and 150% of the FPL,[71] but it stopped new enrollments in CARE Flat Rate at the end of fiscal year 2024.[72]

CARE MB: CARE MB is now Consumers' primary Affordable Payment Plan ("APP"), replacing CARE Flat Rate and having a stated goal of incentivizing customers to "manage their energy usage more efficiently."[73] To be eligible for the program, a household must be at or below 150% of the FPL.[74] Instead of providing consistent payment amounts during the life of the twenty-four-month program as CARE Flat Rate does, CARE MB automatically adjusts the monthly payment amounts after six, twelve, and eighteen months if the customer is consuming at least $5 more or less than originally predicted.[75] And, instead of the $4,000 of forgiven arrears the CARE Fixed Rate program offered, CARE MB only forgives up to $3,000 of arrears.[76] The customer will retain responsibility for paying any arrears beyond $3,000 after they graduate from the twenty-four-month program.[77]

LIA: The LIA program currently provides a $30 credit per month and caps enrollment at 4,200 customers.[78] The Company proposes to increase the credit and customer enrollment cap each year for the next four years, reaching a credit of $55 per month and 8,200 customers by 2029.[79]

[71] Ex. UCC-38 at 32.
[72] *Id.*
[73] *Id.* at 34.
[74] *Id*.
[75] *Id*. at 35.
[76] *Id*.
[77] *Id*.
[78] Ex. UCC-39, Consumer Energy Company's Response to UCC's First Discovery Request, U21870-UCC-CE-0239, at 2.
[79] *Id*.

The Company prioritizes LIA enrollment of customers who already receive support through the CARE program funded by the government, "in order to offset agency costs."[80] This leaves customers who are not currently enrolled in the CARE program potentially at a disadvantage for LIA enrollment.

Many more customers are eligible for the assistance than receive it now or in the future. Any customer who has an income less than 150% of the FPL or who receives Medicaid is technically eligible.[81] Although the Company's proposal to increase the amount of assistance available to customers under the LIA is an improvement from last year, when the Company had no plans to increase enrollment,[82] the LIA program will still only provide assistance to 3.9% of the 135,000 customers who are eligible for the support next year.[83]

RIA: The Company provides an $8 monthly RIA electric credit.[84] Approximately 83% of electric, gas, and combination commodity service customers identified as low-income (meaning their income is at or below 150% of the FPL) receive an RIA credit.[85] The Company is not proposing any changes to the RIA credit in this case.

While $8 per month is not negligible, it hardly has a meaningful impact on bills, especially when compared to the proposed rate increase. The proposed rate increase in this case, from $132 to $146 for a residential customer's average monthly bill, would consume more than the entire RIA credit.[86] The Company has also not provided

[80] Ex. UCC-39 at 2.
[81] Byrom Direct Testimony, at 38, lines 9–18.
[82] *In re Consumers Energy Co.*, MPSC Case No. U-21585, Cira-Reyes Direct Testimony (Sep. 27, 2024), at 5 TR 3493, lines 2–3.
[83] Ex. UCC-39 at 2.
[84] Ex. UCC-38 at 62.
[85] *Id*. at 61.
[86] Connolly Direct Testimony at 9, lines 17–18.

information on why some customers identified as low-income do not currently receive this credit.

Together, these programs and efforts do not do enough to address the magnitude of the affordability issue among the Company's residential customers. With 365,528 residential customers in the Company's service region behind on their energy bill as of December 2024,[87] the need for assistance surpasses the current benefit program offerings. Currently, just one out of every six LMI customers is enrolled in one or more of Consumers' assistance programs.[88] Many customers, including those who are enrolled in at least one assistance program often, do not start receiving benefits until they are already in crisis.[89]

The Company needs to do more to address the assistance gaps in these programs. I acknowledge that the Company has identified barriers to information about assistance programs as an issue and is proposing to allocate $1.87 million into the "[Low Moderate Income] LMI Customer Support Enhancement" project with the goal, in part, of improving access to information.[90] However, as I will explain in more detail later, the Company has not provided concrete details on how or when this project will benefit customers—such as a concrete timeline and a program monitoring and evaluation plan.[91] While I understand that the Company has rejected a Percentage of Income Payment Plan (PIPP) model,[92] a PIPP would simplify the entire assistance system, which would help

[87] *In re MPSC*, MPSC Case No. U-20757, Consumer Energy Company's December 2024 Report on Disconnected Service (Jan. 13, 2025), at 2.
[88] Byrom Direct Testimony at 26, lines 14–15.
[89] Byrom Direct Testimony at 26, line 15.
[90] Byrom Direct Testimony at 25–26.
[91] Ex. UCC-40, Consumer Energy Company's Response to UCC's Second Discovery Request, U21870-UCC-CE-0376, at 1, 3.
[92] Ex. UCC-38 at 5.

solve the information accessibility issue and would help provide truly affordable electricity to LMI customers.

Lack of information available to LMI customers is not the only issue with the Company's LIA, RIA, and CARE MB programs. Many households that are at or above 150% of the FPL cutoff also struggle to pay their energy bill and do not receive assistance from Consumers currently. For example, in 2020, nearly 10% of Consumers Energy customers, or roughly 160,000 customers, were between 150% and 200% of FPL.[93] Of these 160,000 customers, only 5.3% experienced an affordable electricity cost burden of 3% or less.[94] Given recent increases in Consumers' rates and poor challenging economic conditions for many, the number of customers at risk of unaffordable energy burdens is likely increasing. Meanwhile, the existing LIA, RIA, and CARE MB programs are not available to these customers, despite having energy bills that are unaffordable.

Furthermore, the Company's current use of multiple programs is inefficient, confusing, and can have negative impacts on customers. As I described above, the Company has not provided information on why some of its customers who are eligible for multiple assistance programs are not enrolled in one or more of the programs, and there is a persistent lack of information available to LMI customers on how they may sign up for these programs. The Company found that "18% of LMI customers were unaware of how to access help, 36% were unaware they qualify for programs, 25% perceived the process as overly complex and time-consuming . . . and 46% were unfamiliar with utility assistance for low-income families."[95] And, as I will describe

[93] *In re Consumers Energy Co.*, MPSC Case No. U-20697, Colton Direct Testimony (June 24, 2020), at 8 TR 3698, line 6.
[94] *Id*. at lines 8–9.
[95] Byrom Direct Testimony at 33, lines 4–8.

below, enrollment in more than one LIA, RIA, or CARE MB program could in some circumstances actually make customers, who already have a demonstrated lack of knowledge about these programs in general, worse off. The implementation of a PIPP program, in place of CARE MB, would eliminate this adverse outcome.

Q: Could enrollment in multiple programs lead to certain customers receiving less assistance than they should?

A: It appears so. For those who are enrolled in multiple programs, the implementation of these programs could, in some instances, have a negative impact where the application of an LIA or RIA credit to a customer's bill ultimately makes them eligible for *less* assistance under CARE MB than if they had only been enrolled in the CARE MB program. For example, if the Company provides an RIA credit and CARE MB support to a customer's account, the Company will apply the RIA credit to the customer's bill *before* it calculates the amount of assistance, which is based on the monthly cost, under CARE MB.[96] The Company applies this order of operations to LIA credits as well.[97]

To be more concrete, in a scenario in which the customer earns between 0% and 75% of the FPL, under CARE MB, customers who use more than $140 per month on electricity receive $87.67 off their bill each month, while customers who use less than $140 per month are eligible only for a $16.08 reduction in their bill each month.[98] In a scenario in which a customer, who makes 0% to 75% of the FPL, receives both an RIA

[96] Ex. UCC-38 at 66.
[97] *Id*.
[98] *Id*. at 35–36 (In the Consumers' customer experience, "[t]he annual credit is broken down monthly with 70% of it applied from November through May, and 30% of it applied June through October," but here we are using the Company's annualized monthly averages provided in their PIPP report to more simply demonstrate the impact this scenario would have on a customer over a whole year.).

credit and CARE MB assistance, and has a monthly bill near this $140 per month threshold, the dual enrollment could actually result in significantly less overall support to the customer. For example, if an eligible customer who had an electricity bill of $145 per month and is enrolled in both RIA and CARE MB, the Company would have calculated assistance based on a bill of $137 per month (after the application of the $8 RIA credit), and the customer would ultimately pay $120.92 per month. Had they only been enrolled in CARE MB, they would have received much greater assistance under CARE MB and would have paid only $57.33 per month. In this hypothetical, enrollment in the RIA credit, in essence, made the customer's bill $63.59 more expensive each month.

While the Company states that the purpose of applying the RIA and LIA credits before calculating assistance under CARE MB is to reduce "agency costs,"[99] payment assistance programs for LMI customers should not be designed with the goal of reducing agency costs—they should be designed to assist LMI customers. That the Company's current approach—the RIA, LIA, and CARE MB programs—could potentially result in the above-described scenario for even a small number of LMI customers highlights the need for a sliding scale PIPP program that does not have these kinds of gaps. The Company should ensure that the implementation of its assistance programs individually or collectively maximizes the benefits to customers in need.

Q. What's the difference between affordability and assistance?

A: It is important to distinguish that, especially for LMI customers, affordability is not the same as assistance. Affordable bills would be less than 6% percent of their income and

[99] Ex. UCC-39 at 2.

sustainable over the long term, and all customers would have bills they could afford.[100] Assistance programs are a short-term, unsustainable solution that does not address the root cause of people's bills being more than they can afford. In addition, as shown above, assistance programs do not meet all current needs. Consumers does not provide details on the level of energy burdens for customers receiving support through CARE MB, but simple math shows that customers are often paying more than 6% of their income even with the assistance.[101] For instance, a family of four at 50% of the FPL with $215 per month in utility bills would pay 14.6% of their income *after* application of CARE MB assistance, a severe energy burden.[102] Consumers' assistance programs are, as a whole and individually, insufficient—they do not provide the support that energy-insecure customers need and they do not provide a long-term, sustainable affordability solution.

Q: Has the Company conducted any formal analysis on customer affordability?

A: No. While the Company agrees with the Commission's definition of "energy affordability" described above ("the extent to which a household has the resources to meet their home energy needs for heating, cooling and other uses in a healthy, sustainable, and energy efficient manner without compromising a household's ability to meet other basic needs"[103]) and has incorporated that definition into its LMI Customer

[100] Ex. UCC-5 at 8.
[101] Ex. UCC-38 at 36.
[102] The FPL for a family of four is $32,150. 50% of $32,150 = $16,075; $215 in electricity bill minus $19.58 in CARE MB assistance = $195.42 per month; $195.42 per month times 12 months = $2,345.04 per year; $2,345.04 in annual electric bills divided by $16,075 annual income at 50% of the FPL for a family of four = 14.6% energy burden. *See* Ex. UCC-41, *Federal Poverty Level (FPL)*, HEALTHCARE, https://perma.cc/MP2J-V89A (last visited Sep. 21, 2025), at 1–2; *see also* Ex. UCC-38 at 35.
[103] *In re MPSC*, MPSC Case No. U-20757, Order (Dec. 21, 2023), at 36.

Support Enhancement program, it does not have plans to conduct an affordability analysis incorporating the details included in the Commission's definition of affordability.[104] This is despite the fact that Consumers is well aware that a significant percentage of its customers have difficulty paying their bills. As Witness Byrom states, "LMI customers account for more than 1 of every 3 customers in Consumers Energy's service territory; 11% are low income, meaning they are in crisis and unable to pay their energy bill; 26% are moderate income, commonly identified as being one crisis away from being able to pay their energy bill. Currently, only 1 in 6 LMI customers engage in Energy Assistance programs…"[105] Thus, the Company is knowingly charging rates that are unaffordable, which leads customers to choose among basic needs.

Q: Do you have any information about whether Consumers has assessed if its customers can afford its current rates and the proposed rate increase?

A: Although Consumers claims not to have done an affordability analysis, the Company uses customer identifiers that indicate an awareness of how affordable their programs are for their customers. For example, the Company classifies customers as "won't pay" (defined as "frequently late; has multiple late payments or open invoices") and "can't pay" (defined as "has moderate on-time payment behavior (at least 50%)").[106] It is also aware of when certain individual customers have lost their jobs or lost some income.[107]

[104] Ex. UCC-42, Consumer Energy Company's Response to UCC's First Discovery Request, U21870-UCC-CE-0234, at 1–3.
[105] Byrom Direct Testimony at 27, line 22 to 28, line 3.
[106] Ex. UCC-43, Consumer Energy Company's Response to UCC's First Discovery Request, U21870-UCC-CE-0233_Byrom_ATT_1, at 4; Ex. UCC-44, Consumer Energy Company's Response to UCC's Second Discovery Request, U21870-UCC-CE-0369, at 1.
[107] Ex. UCC-45, Consumers Energy Company's Response to UCC's First Discovery Request, U21870-UCC-CE-0237, at 3.

Therefore, although the Company says it are not doing any affordability analyses, the Company is at least aware that some of their customers cannot pay or are financially struggling. At the same time, the Company still seeks to raise its rates by 11%[108] and rejected the piloted PIPP program, which would have provide the most support to their customers who are experiencing energy insecurity.[109]

The Commission should require the Company to perform a fulsome official affordability analysis incorporating the Commission's definition of energy affordability to ensure its programs are adequately addressing the affordability crisis among its customers before the Commission approves the rate increase.

Q: If Consumers' current set of bill assistance programs is insufficient, what do you recommend as an alternative and why?

A: While I understand that the Company has rejected a Percentage of Income Payment Plan (PIPP) model, such a program would nonetheless be highly beneficial to customers. A PIPP is an individual income-based alternative to the mix of programs that Consumers offers currently.[110] A PIPP is a longer-term cure instead of the short-term, band-aid approach offered by the current suite of bill assistance programs. PIPP offers a proactive, consistent approach for LMI customers by setting a fixed percentage of income to go towards energy bills, as opposed to applying for assistance after arrearages grow. It also provides individualized assistance calculated based on a customer's income, which is notably fairer than using broad income brackets to determine assistance, as CARE MB

[108] Connolly Direct Testimony at 9, line 17.
[109] Ex. UCC-38 at 83.
[110] *Id*. at 19.

does.[111] As other intervenors explained in their comments in the PIPP docket, "[t]he CARE program . . . was innovative when Consumers first proposed it in 2013. But its payments are based on tiers—25-75%, 76-110%, and 111-150% FPL—which means that participants with incomes at the top end of each range will receive a greater proportion of energy burden relief than those at the low end."[112]

I do not believe that the Company explained sufficiently why it will not implement a PIPP program. The Company, following a 24-month PIPP pilot program which concluded in March 2025, [113] ultimately decided not to implement a full-scale PIPP program for LMI customers, asserting that the costs of the program outweigh the benefits.[114] The Company, in asserting this, is overlooking key benefits of a PIPP program to LMI customers, which would help to address many of the shortcomings of the current suite of existing programs, which I have described above.

In terms of the basic structure of Consumers' PIPP pilot, the pilot calculated customers' monthly payment at 3% for a single utility (gas or electric) or 6% for the combination of the two.[115] Customers had a minimum monthly payment of $10.[116] To be eligible for the program, a customer's income must have been at or below 150% of the

[111] *Id*. at 19, 36.
[112] Ex. UCC-46, MICH. ENV'T COUNCIL, NAT. RES. DEF. COUNCIL, CITIZENS UTIL. BD. OF MICH. ECOLOGY CTR. AND VOTE SOLAR, U-21021 COMMENTS ON DTE ELECTRIC COMPANY AND DTE GAS COMPANY AND CONSUMERS ENERGY COMPANY PIPP PILOTS (2025), at 14 (filed in *In re Consumers Energy Co.*, MPSC Case No. U-21021, Comments on DTE Electric Company and DTE Gas Company and Consumers Energy Company PIPP Pilots by Michigan Environmental Council, Natural Resources Defense Council, Citizens Utility Board of Michigan, Ecology Center, and Vote Solar (June 12, 2025), at 14).
[113] Ex. UCC-38 at 19.
[114] *Id*. at 83.
[115] *Id*. at 20.
[116] *Id*.

FPL.[117] There was a $6,000 arrears cap to enter the program, and by graduation, the Company forgave all arrears up to $6,000 limit.[118]

Despite these tangible improvements over the existing affordability programs, the Company recommended abandoning the PIPP program, citing "substantially higher" costs.[119] Specifically, the Company estimated that PIPP would cost $232 million per year in comparison to CARE MB, which would cost an estimated $156 million per year.[120] For this reason, the Company recommended continuing with the APPs already in place and not adopting the PIPP program.[121] However, the Company admits that "lower customer payment amount obligations" were "[t]he main contributor to the higher program costs" for PIPP.[122] In other words, since customers had to pay less out of pocket under PIPP and the PIPP program covered a greater portion of their monthly bill than the CARE MB program, the PIPP program was more expensive to administer. However, it is reasonable to expect that a program that provides more financial support will likely be more expensive to administer. Additionally, DTE recently found that its Payment Stability Plan (PSP) program, which is similar to PIPP, is a sustainable, administrable program.[123] Even if PIPP is more expensive than CARE MB, that does not mean the costs are not worth the benefits.

[117] *Id*.
[118] *Id*.
[119] *Id*. at 5.
[120] *Id*. at 81. In the same Report, however, the Company notes that for the month of January 2025, PIPP was actually less expensive to administer than CARE MB by an average of $48 per customer. It is unclear why this is the case, and the Company should clarify this discrepancy. *See id*. at 65.
[121] *Id*. at 5.
[122] *Id*. at 80.
[123] *In re DTE Gas Co. and DTE Electric Co.*, MPSC Case No. U-20929, DTE Energy PSP Pilot Report (Jan. 29, 2025), at 3–4.

While Consumers measured the benefit of these programs in terms of their disconnection rates, I believe energy affordability, especially for customers most in need, is a more important metric and should be factored into the decision about whether Consumers should move forward with a PIPP program. The Company concluded that the APPs were comparably successful because "disconnection rates for non-payment were similar between all programs"[124] and "payment behaviors improved positively regardless of the APP."[125] While disconnection rates and payment behavior are important, they were *similar* between programs, so we need to look to other metrics to help *differentiate* between the success of these programs.

Disconnection rates also do not tell the full story. As I discussed above, research has clearly established that energy burdens of more than 6% of a customer's income (as many customers enrolled in CARE MB still experience) are unaffordable. To avoid devastating shutoffs and pay bills, customers often forego other necessities and make difficult and unsustainable decisions, such as keeping heat dangerously low in the winter.[126] The Company admits that it "did not analyze whether customers enrolled in CARE Flat and CARE MB sacrificed basic necessities to pay their bills, compared to those in the PIPP program."[127] Thus, the Company's decision to measure success based on disconnection does not address a key issue that these programs should address: energy insecurity and affordability.

The benefits of the PIPP program are evidenced by the more positive customer experience with the PIPP program than with CARE MB. Under the PIPP pilot, 95% of

[124] Ex. UCC-38 at 80.
[125] *Id*. at 53.
[126] Ex. UCC-8 at 3, 8.
[127] Ex. UCC-47, Consumers' Response UCC's Third Discovery Request, U21870-UCC-CE-0685, at 2.

customers said they were highly satisfied with the PIPP program compared to 84% of customers expressing satisfaction with CARE MB.[128] It's important to note that customers were not asked to compare programs, only to rate their satisfaction with the program they were enrolled in. On average, customers making between 20% and 75% of the FPL in the CARE MB program paid almost four times the monthly bill amount that customers in the same income bracket enrolled in the PIPP pilot paid.[129] The Department of the Attorney General found that Consumers' PIPP program resulted in a reduction of energy burdens "ranging from 45% to 83% . . . compared to pre-pilot burdens across all FPL tiers and services."[130] Just because 84% of customers were "satisfied" by receiving some help through CARE MB does not mean they would not prefer the substantially greater assistance through the PIPP program, especially if they were offered the more affordable alternative. While the Company called the PIPP program "unsustainable" because it was more expensive than CARE MB,[131] what is truly unsustainable is the energy insecurity that LMI community members continue to experience, especially in the face of increasing energy costs.

[128] Ex. UCC-38 at 71.

[129] The average electricity bill for a customer making between 20% and 75% of the FPL in the CARE MB program was $125 per month; The average electricity bill for a customer making between 20% and 75% of the FPL in the PIPP program was $32 per month. *Id*. at 196, 198.

[130] Ex. UCC-48, MICHAEL E. MOODY & CHRISTOPHER BZDOK, MICH. DEP'T OF ATT'Y GEN. & CITIZENS UTIL. BD. OF MICH., U-20929 & U-21021 COMMENTS ON APPLICATIONS OF DTE GAS COMPANY., DTE ELECTRIC COMPANY AND CONSUMER ENERGY COMPANY FOR APPROVAL OF PIP PILOT PROGRAM (2025), at 5 (filed in *In re Consumers Energy Co.*, MPSC Case No. U-21021, Comments of the Attorney General and CUB (June 12, 2025), at 5).

[131] Ex. UCC-38 at 81.

Q: What actions do you recommend the Commission take regarding affordability in this case?

A: In order to provide affordable energy to Consumers' customers, the Commission should require the Company to adopt a PIPP. A PIPP would simplify the assistance offerings, ensure that the interaction between multiple APPs does not make customers worse off, and provide affordable electricity, at a 6% total or 3% electric energy burden, to LMI customers.[132] Although the Company's PIPP pilot served only those customers at or below 150% of the FPL,[133] the Commission should require Consumers' PIPP program to serve all customers at or below 200%, as 2020 data show that only 5.3% of customers between 150% and 200% of the FPL experienced an affordable electricity cost burden of 3% or less.[134]

In the meantime, I recommend that the Commission support the proposed increase to the LIA credit and cap expansion on the LIA credit.

In addition, the Commission should require the Company to perform a regular affordability analysis, incorporating the Commission's definition of energy affordability, to ensure its programs are adequately addressing the affordability crisis among its customers before the Commission approves its requested rate increase.

Given the concerns about the affordability impacts of the proposed instant case's rate increase, UCC requests that the Commission scrutinize the Company's request and limit the rate increase to the greatest extent possible.

[132] *Id*. at 20.
[133] *Id*. at 19.
[134] *In re Consumers Energy Co.*, MPSC Case No. U-20697, Colton Direct Testimony (June 24, 2020), at 8 TR 3698, lines 8–9.

Finally, the Commission should create an interim heat extreme weather policy in the present case that ensures time- and weather-advisory protections that extend past the date of an extreme heat event, if Case No. U-20140 will not yield a policy before next summer.

III. RELIABILITY

Q: Is Consumers Energy's electric utility service reliable?

A: No. In response to years of concerns regarding the frequency and duration of outages experienced by Consumers' customers, the Commission requested an audit in MPSC Case No. 21305 to evaluate the Company's distribution system and make recommendations to improve service reliability.[135] The audit, completed by The Liberty Consulting Group last year, placed Consumers within the fourth quartile of utility companies for average outage duration and found that the Company's customers experience outages of at least four and eight hours at rates "greater than usually acceptable."[136] Furthermore, the audit found that in 2023, "more than 10 percent of Consumers' customers experienced four or more interruptions and more than 25 percent of its customers experienced interruptions greater than eight hours."[137]

Unfortunately, this data comes as no surprise to me; I regularly hear from Consumers customers, particularly those from low-income and/or BIPOC communities, who have experienced service outages lasting anywhere from hours to days. These

[135] *In re DTE Electric Co. & Consumers Energy Co.*, MPSC Case No. U-21305, Order (June 12, 2025) [hereinafter U-21305 Order], at 1–2.
[136] *In re DTE Electric Co. & Consumers Energy Co.*, MPSC Case No. U-21305, Consumers Energy Report Part One (Sep. 23, 2024), at 4–5.
[137] *Id*. at 5.

outages can cause significant harm to already vulnerable communities, from detrimental health impacts[138] to considerable financial strain.[139]

Q: Is there a basis for thinking that different kinds of communities experience reliability differently in Consumers' service territory?

A: Yes. The Company identifies vulnerable communities using the Michigan Environmental Justice Screen (MIEJ Screen) tool; census tracts with a MIEJ Screen composite score at or above the 80th percentile are considered vulnerable "EJ communities."[140] In his Rebuttal Testimony for Consumers' 2024 rate case, Case No. U-21585, Consumers' Director of Corporate Strategy, Witness Michael P. Kelly, summarized a recent study in which the Company analyzed how these "EJ census tracts perform relative to similar non-EJ urban census tracts."[141] According to Witness Kelly, the results revealed that census tracts at or above the MIEJ Screen 80th percentile "perform worse on key reliability metrics."[142] The discovery of this service disparity resulted in Consumers' EJ Resiliency Plan, which proposed $600 million in "targeted strategic investments" to "eliminate EJ circuits experiencing worse [reliability] than the industry average" within the next ten years.[143] In his testimony in this case, Witness Kelly reaffirmed the analysis

[138] Ex. UCC-49, Joan A. Casey et al., *Power Outages and Community Health: A Narrative Review*, 7 CURRENT ENV'T HEALTH REPS. 371 (2020), at 6–9.
[139] *See* Ex. UCC-50, Patrick Madamba, *How Do Power Outages Affect Households?*, U.S. CENSUS BUREAU (Oct. 2, 2024), https://perma.cc/FNR5-VW8K, at 3 (stating that power outages frequently lead to food and medicine spoilage, hotel stays, and home repairs, all of which increase costs for impacted customers).
[140] Kelly Direct Testimony at 72, lines 1–3.
[141] *In re Consumers Energy Co.*, MPSC Case No. U-21585, Kelly Rebuttal Testimony (Nov. 5, 2024), at 5 TR 1011.
[142] *Id*. at 5 TR 1016, lines 2–4.
[143] *Id*. at 5 TR 1016–18.

in U-21585 (and U-21389), stating, "Those analyses have built on one another, and each remains valid even as the Company has deepened its understanding."[144]

Q: What did the Commission order Consumers to do regarding reliability in the last rate case, Case No. U-21585?

A: In Case No. U-21585, the Commission ordered Consumers to "present its EJ Resiliency Plan with specified proposed investments" in its next rate case.[145] Further, the Commission required that Consumers complete a previously-requested "regression analysis" of EJ reliability "includ[ing] data on residential disconnections" and present the results in the Company's next rate case.[146]

Q: Based on the Company's testimony and exhibits in the current case, has Consumers responded to the Commission's U-21585 order in a manner that will meaningfully reduce inequities in service reliability?

A: Based on Consumers' testimony and exhibits for the current rate case, I believe that the Company could address the existing inequities in its service reliability more expeditiously. Specifically, I think:

1. The Company needs to do more to meet the investment targets the Commission approved for its EJ Resiliency Plan.
2. The Company needs to take more action to address inequities revealed in its EJ reliability regression analysis.

[144] Kelly Direct Testimony at 72, lines 5–7.
[145] *In re Consumers Energy Co*., MPSC Case No. 21585, Order (Mar. 21, 2025) [hereinafter U-21585 Order], at 436.
[146] *Id*.

Q: Are there any aspects of the Company's EJ Resiliency Plan, now called the Vulnerable Communities Resilience Plan, that you like?

A: Yes.

First, I appreciate that the Company has acknowledged that "there are particular EJ communities that do face reliability challenges, and given their socioeconomic vulnerabilities[,] the Company intends to direct specific new investments to those communities to improve their reliability."[147]

Second, while I am not currently in a position to comment on whether $600 million is the right amount to invest, I recognize that this is a substantive investment, in total. I also appreciate that the vast majority of these investments are incremental to the Company's Reliability Roadmap.[148]

Third, I appreciate the plan's "goal of ensuring that every EJ circuit in the Company's service territory has SAIDI, including MEDS, that is in the second IEEE quartile or better…. ensur[ing] that no EJ circuits experience worse than industry average reliability, and [doing] so including MEDs to account for the actual experience of those customers."[149]

Fourth, I appreciate the efforts the Company has made to share more geographical information with the public and interested parties about these issues.[150]

[147] Kelly Direct Testimony at 72, lines 9–11.
[148] *Id.* at 72–73.
[149] *Id.* at 72, lines 17–21.
[150] *Id.* at 79, lines 5–15.

Q: Please explain your concerns regarding the Company's Vulnerable Communities Resiliency Plan.

A: Based on Consumers' testimony and exhibits for the current case, I am concerned that the Company is not on track to meet either the timeline or investment levels the Commission approved for its EJ Resiliency Plan. In its U-21585 order, the Commission made clear that it was approving Consumers' $600 million EJ Resiliency Plan and that it "expect[ed to] see the more detailed version, with specific proposed investments, in the company's next electric rate case."[151] While Consumers did provide a list of proposed initial investments under its Vulnerable Communities Resiliency Plan in testimony for the current case, these projects only add up to a total of $30 million in investments over the coming year.[152] Consumers Witness Kelly reiterated in his testimony that the Company plans to invest $600 million total "[o]ver a period of several years."[153] However, $30 million in the first year does not put the Company on pace for the expected $600 million in investments over a 10-year period, a timeline that is already quite conservative for addressing these inequities. Improving reliability for vulnerable communities is an urgent need and should be prioritized as such. Unfortunately, neither Witness Kelly nor any other Consumers witness explains why only $30 million in projects were selected for the current year, or how the Company plans to meet the ten-year targets the Commission agreed with in Case No. U-21585.

[151] U-21585 Order at 375.
[152] Kelly Direct Testimony at 74, lines 12–15, Ex. A-167 at 22.
[153] Kelly Direct Testimony at 73, lines 9–20.

Q: Please explain your concerns regarding the Company's EJ reliability regression analysis.

A: Consumers' EJ reliability regression analysis appears to confirm that inequities based on race and socioeconomic status exist within its distribution system. However, based on the discussion of those results in testimony for this case, I am concerned that the Company is not making mitigation of those disparities enough of a priority.

First, Consumers may again be relying on questionable methodology to conclude that EJ communities experience better reliability overall. For instance, as summarized by Witness Kelly, the regression analysis appears to demonstrate that when "compar[ing] average reliability of different types of census tracts, . . . is consistently the EJ, urban, low-income, and high-percent-minority tracts that have better reliability." As discussed extensively in Witness Kelly's rebuttal testimony for the previous rate case, simply comparing reliability in EJ communities to systemwide averages is likely to conceal inequities.[154] This occurs because urban communities generally experience superior reliability compared to rural communities, which Consumers' regression analysis indeed confirmed,[155] and most EJ communities are located in urban areas. Consumers' systemwide comparisons of EJ and non-EJ, low-income and high-income, and high-percent-minority and low-percent-minority census tracts do not appear to account for population density, meaning that while there is no difference at the categorical level, there could be a difference if one takes into account the number of people affected. In addition, Witness Kelly goes on to concede in his testimony that the regression analysis

[154] *In re Consumers Energy Co.*, MPSC Case No. U-21585, Kelly Rebuttal Testimony (Nov. 5, 2024), at 5 TR 1006–16.
[155] Kelly Direct Testimony at 76, lines 20–22.

also found "instances where increasing poverty levels and increasing unemployment rates are correlated with worsening reliability" and "where circuits serving EJ census tracts are more likely to experience customer interruptions."[156] The analysis itself notes these discrepancies and suggests they "may warrant further study."[157] This seems to contradict directly Kelly's statement that "[t]here is nothing apparently systemic or unique about EJ census tracts" that leads to worse reliability outcomes.[158]

Furthermore, the regression analysis revealed racial disparities in shutoff data for which the Company has provided neither an explanation nor concrete mitigation plans. As summarized by Witness Byrom, the analysis found that "when all other modeled variables are held constant[,] increasing Percentage Minority Population in a census tract is statistically significant and associated with increasing disconnection rate."[159] In other words, and to be direct, there is a racial bias in the Company's shutoff rates. Witness Byrom confirmed that customers' racial identity is not expressly available to Consumers' employees engaged in the disconnection process, suggesting that race cannot be a factor.[160] However, Consumers confirmed in discovery that those employees have access to customers' names and addresses,[161] which can nonetheless serve as race-identifying data points. Moreover, despite providing reports regarding customer segmentation by

[156] *Id*. at 77, lines 5–8, 14–16.
[157] *Id*., Ex. A-135 (MPK-25), at 14.
[158] *Id*. at 78, lines 10–11.
[159] Byrom Direct Testimony at 47, lines 15–16.
[160] Ex. UCC-51, Consumers Electric's Response to UCC's First Discovery Request, U21870-UCC-CE-0233, at 2–3 (not listing race as an example of the "[i]nformation the Company collects on customers that is available on the customer account level").
[161] *Id*. at 2 ("Information the Company collects on customers that is available on the customer account level includes: Customer name, service address, Consumers Energy account number, mailing address, phone number, email address, date of birth, last three digits of a customer's driver's license number, and last four digits of their social security number.").

payment frequency and disconnection,[162] the Company has failed to provide *any* meaningful information about why this bias exists. Finally, the problem-solving process, which was initially set to conclude on September 24, 2025,[163] has been pushed to December 31, 2025,[164] raising questions about whether resolving existing racial disparities is currently among the Company's top priorities.

Q: What actions do you recommend the Commission take in light of these concerns?

A: I recommend the Commission take the following actions:

1. Require that Consumers provide a detailed plan for meeting the ten-year EJ Resiliency Plan targets that the Commission approved in Case No. U-21585. Consumers' proposal for just $30 million in initial Resiliency Plan investments deserves extra scrutiny when coupled with questions about the Company's interpretation of its EJ reliability regression analysis. If Consumers wants to charge higher rates while its service still lags behind industry standards for reliability, its customers deserve reassurance that those dollars will largely be spent to improve their service and eliminate inequities as quickly as possible.
2. Require the Company to cease all shutoffs until it can determine why BIPOC customers are experiencing increased shutoff rates and present a plan to stop that bias from continuing. Every day that the Company continues to shutoff customers without

[162] *See generally* Ex. UCC-52, Consumers Electric's Response to UCC's First Discovery Request, U21870-UCC-CE-0233_Byrom_ATT_2 (exploring the relationship between LMI datapoints and disconnections); *see also* Ex. UCC-43; *see also* Ex. UCC-53, Consumers Electric's Response to UCC's First Discovery Request, U21870-UCC-CE-0233_Byrom_ATT_3.

[163] Ex. UCC-51, at 3.

[164] Ex. UCC-54, Consumers Electric's Response to UCC's Second Discovery Request, U21870-UCC-CE-0368.

having addressed the cause of this disparity, the Company is potentially committing new discriminatory acts against customers. Furthermore, the Company should also be required to create a fund to compensate customers shutoff by Consumers for improper reasons.

IV. INVESTMENT RECOVERY MECHANISM

Q: What did the Commission order regarding the Investment Recovery Mechanism (IRM) in the last rate case, Case No. U-21585?

A: The Commission allowed Consumers to increase its Year 2 IRM funding from $49.3 million[165] to $86.3 million to pay for reliability investments the Commission found to be "reasonable and prudent."[166] The Commission justified this approval by noting that "the IRM presents the not insignificant benefit of ensuring that the amounts that are approved for particular work will actually be spent on that work or else be refunded to customers."[167]

Q: What is Consumers proposing regarding the IRM in this case?

A: The Company is proposing to extend the IRM for another two years and add two additional sub-programs for investment.[168] The two new programs are the "Repetitive Outages" subprogram and the "Vulnerable Communities Resiliency Plan."[169] To support this expansion, Consumers is proposing over $352 million in IRM expenses, with around

[165] U-21585 Order at 360.
[166] *Id*. at 365.
[167] *Id*.
[168] Kelly Direct Testimony at 100, lines 16–21.
[169] *Id*. at 101, lines 9–10.

$30.3 million going toward the new Repetitive Outages program and $30 million going toward the new Vulnerable Communities Resiliency Plan.[170]

Q: In light of the IRM's Year 1 performance, do you agree with Consumers' proposal to increase the capital spending and the timeline of the IRM based on the IRM's Year 1 performance?

A: While I support the investments in vulnerable communities in general and appreciate the fact that Consumers has spent a greater percentage of the IRM on EJ communities than EJ persons are of the population in Consumers' territory,[171] as I will discuss in more detail below, Consumers did not meet project timelines and spent above its approved amounts in Year 1 of the IRM. Thus, while I recognize the Company's and the Commission's goal of ensuring "proactive spending"[172] to develop a reliable and resilient system, I have some concerns about approving another IRM before reconciliation for the current IRM has been completed and approved.

According to Consumers' application for Year 1 reconciliation, the Company exceeded its approved spending by more than $16.8 million.[173] The Company also cites "a series of delays" as the reason why it could not complete all of its fractionalization projects for the Resiliency program as planned during Year 1.[174] Notably, while the

[170] *Id*. at 102, fig. 31.
[171] *Id.* at 106, lines 9–17 (noting that 9.5% of spending was in EJ communities as compared to "4.1% to 9.2% of the Company's 1.9 million customers"). That said, I do not know how the expenditures on EJ communities compare to the overall need in EJ communities. In other words, it is entirely possible that the Company should have devoted an even higher percentage of funds to EJ communities if their needs were proportionately greater.
[172] *Id*. at 106, lines 19–20.
[173] *In re Consumers Energy Co.*, MPSC Case No. U-21918, Kelly Direct Testimony (May 30, 2025), at 4, lines 2–3.
[174] Kelly Direct Testimony at 105.

approved spending of $8.973 million for Resiliency included four fractionalization projects, the Company only completed one despite an actual spend of nearly $8.0 million. In other words, Consumers used nearly all of its approved funding for the Resiliency sub-program on just *one* project.[175]

Consumers should elaborate on why its Year 1 cost projections were so inaccurate. Moreover, Consumers must show through reconciliation of its Year 2 funding that it is capable of completing projects on time and within budget. While I certainly support the investments in vulnerable communities, I also think that ratepayers should not continuously absorb unexpected cost increases and less than anticipated reliability improvements.

Q: What additional concerns do you have about the IRM's Year 1 performance, specifically regarding the reconciliation process?

A: I would have appreciated it if the Company had included a more thorough equity analysis in the Company's current reconciliation application.[176] In Case No. U-21389, the Commission stated that it would need to "consider, among other things, evidence presented on whether the investments are, in fact, being deployed equitably, whether the investments exacerbate or perpetuate racial or socioeconomic disparities in service, whether there has been a positive impact on reliability and resilience, whether there is sufficient opportunity for scrutiny of the investments, and whether customers have

[175] *Id*. at 104–105.
[176] *See generally In re Consumers Energy Co.*, MPSC Case No. U-21918, Application (May 30, 2025) [hereinafter U-21918 IRM Reconciliation Application].

benefitted from the IRM mechanism" to determine whether the "IRM should continue beyond Year 2."[177]

In its current reconciliation application, the Company notes that it spent $6.3 million in EJ communities, or 9.5% of the $66.1 million spending.[178] Witness Kelly notes that this percentage compares favorably to the percentage of EJ communities in the Company's service territory, which varies from 4.1% to 9.2% depending on definitions.[179]

While I appreciate that EJ communities received a significant portion of the spending in the Year 1 IRM, I do not know how the expenditures on EJ communities compare to the overall need in EJ communities. In other words, it is entirely possible that the Company should have devoted an even higher percentage of funds to EJ communities if their needs were proportionately greater. To that end, it would have been helpful if the Company could have tied the analysis of its Year 1 IRM in the reconciliation case and this case to the needs in EJ communities. Doing so would have spoken more directly to the Commission's mandate that the Company present analysis on "whether the investments are, in fact, being deployed equitably, whether the investments exacerbate or perpetuate racial or socioeconomic disparities in service, whether there has been a positive impact on reliability and resilience, whether there is sufficient opportunity for

[177] *In re Consumers Energy Co.*, MPSC Case No. U-21389, Order (Mar. 1, 2024) [hereinafter U-21389 Order], at 272–273.
[178] *In re Consumers Energy Co.*, MPSC Case No. U-21918, Kelly Direct Testimony (May 30, 2025), at 8, lines 11–12*; see also* Kelly Direct Testimony at 106, lines 9–17.
[179] *In re Consumers Energy Co.*, MPSC Case No. U-21918, Kelly Direct Testimony (May 30, 2025), at 8, line 16.

scrutiny of the investments, and whether customers have benefitted from the IRM mechanism."[180]

Q: Are you opposed in principle to the IRM model?

A: No. While I have argued against multi-year IRMs in the past, I believe that a short-term IRM could be a desirable model for funding reliability improvements because it creates greater accountability for the utility to follow through on promised investments while providing intervenors and consumer watchdogs sufficient opportunity to scrutinize spending outcomes. This ensures that ratepayer funds are spent as efficiently as possible and for the benefit of customers. I also appreciate that the Company is directing these resources in a meaningful part to EJ and other vulnerable communities, as the Commission directed.[181]

Q: What actions do you recommend the Commission take regarding Consumers' proposal to expand the IRM?

A: While I support increased investments in vulnerable communities, I have some concerns from a ratepayer perspective about whether the Commission should approve another increase in IRM spending before reconciliation for the current two-year IRM has been completed. The Company can also report more thoroughly on the linkage between the percentage of the investments in EJ communities relative to the needs of those communities. Ultimately, Consumers must prove it can deliver on its promise to establish

[180] U-21389 Order at 273.
[181] *See* Kelly Direct Testimony at 105–106 (quoting U-21389 Order).

a more reliable and resilient network for all its customers—especially for LMI and BIPOC customers—without overspending ratepayer dollars.

V. ENVIRONMENTAL JUSTICE

Q: In what ways can the energy system negatively impact EJ communities?

A: The energy system can have several direct effects on the experience of EJ communities. For example, unreliable power can have a disproportionate impact on EJ communities. Members of these communities often "have more difficulty replacing spoiled food and medicine following power interruptions and may have fewer resources to secure back-up power or find alternative accommodations during extended power outages."[182] As another example, EJ communities are much more likely to be near power plants than non-EJ communities.[183] As a result, "co-pollutants from electricity generation are responsible for significant health impacts on local communities, and contribute to the disproportionate health-impairing pollution burden that exists in many environmental justice communities."[184] EJ communities are also disadvantaged if utilities do not invest in environmentally sustainable technology, such as electric vehicle charging, rooftop solar, community solar, and storage, in EJ communities but do in non-EJ communities.[185]

[182] *In re MPSC*, MPSC Case No. U-20147, Consumers Energy Company's Electric Distribution Infrastructure Investment Plan ("EDIIP") 2024-2028 (Sep. 27, 2023) [hereinafter U-20147 EDIIP], at 45.
[183] Ex. UCC-55, Juan Declet-Barreto & Andrew A. Rosenberg, *Environmental Justice and Power Plant Emissions in the Regional Greenhouse Gas Initiative States*, 17 PLOS ONE 1 (2022), at 9.
[184] *Id*. at 2.
[185] *See* U-20147 EDIIP at 45.

Q: How does the Company define an EJ community?

A: The Company defines environmental justice communities as census tracts that score above the 80th percentile in their MiEJScreen Overall Score.[186] MiEJScreen measures environmental stressors and public health conditions in communities and produces a score that allows for cross-community comparisons.[187] Among other factors, MiEJScreen accounts for exposure to environmental pollutants, proximity to hazardous waste, population demographics like income, race, education attainment, and the percentage of the population that may be sensitive to harmful environmental conditions due to their health, age, and housing status.[188]

Q: How has the Company assessed environmental justice issues in the past?

A: In Case No. U-21224, Consumers Energy agreed to "propose a plan no later than its next EDIIP to incorporate environmental justice and equity into its analysis to prioritize distribution investments, and make best efforts to consider equity in its distribution system planning in its next general electric rate case."[189] In the Settlement Agreement in MPSC Case No. U-21224, Consumers agreed to "study reliability performance and hosting capacity on circuits that overlap with EJ communities."[190]

Since the U-21224 settlement, the Company has taken some steps with regard to EJ analysis. In Case No. U-21389, the Company provided a "preliminary" EJ analysis.[191]

[186] *Id*.
[187] Ex. UCC-56, Dept. of Environment, Great Lakes, and Energy, *MiEJScreen: Environmental Justice Screening Tool (Version 1.0)*, MICHIGAN.GOV, https://perma.cc/U865-JXTL (last visited Sep. 21, 2025), at 1.
[188] *Id*. at 4.
[189] *In re Consumers Energy Co.*, MPSC Case No. U-21224, MPSC Order (Jan. 19, 2023), at 5.
[190] Kelly Direct Testimony at 71–72.
[191] Kelly Direct Testimony at 72, lines 3–5.

The Company provided a more substantial analysis in its Electric Distribution Infrastructure Investment Plan (EDIIP) in Case No. U-20147.

In the Company's EDIIP, the Company incorporated EJ into its distribution planning through its "flagging" methodology. The Company determined which circuits to prioritize for investments through a system of "flags," which note concerns based on the circuit's performance.[192] These flags included concerns such as reliability and safety.[193] Any circuit that received two or more flags was considered a priority circuit and was highlighted for investment.[194] In 2023, the Company added EJ as a component that would count as one of the two flags necessary for a circuit to be considered a priority circuit.[195] (Note that Consumers has since said that the Vulnerable Communities Resiliency Plan identifies EJ circuits and in general supersedes the EJ flag.[196])

The Company also noted that its Grid Archetype approach had been directing more investment into EJ communities without explicitly accounting for environmental justice.[197] As discussed by Consumers Witness Michael Kelly, "the purpose of Grid Archetypes is to consider LVD circuit characteristics beyond reliability metrics to prioritize investments, ensuring that investments are optimally made across the Company's distribution system and across different capital spending programs."[198] The Company's Grid Archetype approach did this by categorizing circuits into one of seven archetypes, determined by characteristics of the circuit, including whether the circuit is in

[192] *In re Consumers Energy, Co.*, MPSC Case No. U-21585, Kelly Direct Testimony (Nov. 5, 2024) at 5 TR 852, lines 5–6.
[193] U-20147 EDIIP at 44.
[194] *Id*.
[195] *Id*. at 50.
[196] Kelly Direct Testimony at 74, lines 19.
[197] U-20147 EDIIP at 46–47.
[198] Kelly Direct Testimony at 14, lines 15–18.

a rural or urban area, whether circuits had shorter or longer lines, and the frequency of outages on a given circuit.[199] The Company then allocated its spending into circuits within the different archetypes, guided by a series of "guardrails" to ensure that each archetype received appropriate investment.[200] In its EDIIP, Consumers noted that grid Archetype 4, described as "urban customers, longer circuits with high customer density that are more susceptible to outages,"[201] had considerable overlap with EJ communities.[202] Despite the finding that EJ communities considerably overlapped with grid Archetype 4, with its greater susceptibility to outages, the Company's analysis concluded that EJ communities have better reliability than the system average.[203]

In Case No. U-21389, the Commission ordered the Company to provide more information and analysis. They asked Consumers to provide "a full summary of the environmental justice and equity considerations in its next rate case, including a detailed discussion of how proposed environmental justice changes will both impact customer rates and be implemented on such rates[.]"[204] The Company was additionally directed to provide a regression analysis "in support of reliability investments in the company's distribution system in future filings[.]"[205]

The Company responded last year, in Case No. U-21585, by providing a more in-depth analysis of EJ issues, which I appreciated. In this case, while I appreciate the

[199] *Id.* at 15, fig. 2.
[200] *Id*. at 15–16.
[201] *Id*. at 15, fig. 2.
[202] U-20147 EDIIP at 46.
[203] *Id*. at 47–49. Specifically, this analysis looked at SAIDI excluding MEDs, SAIFI excluding MEDs, and CAIDI excluding MEDs.
[204] *In re Consumers Energy Co.*, MPSC Case No. U-21389, Order (Mar. 1, 2024), at 314.
[205] *Id*. at 313.

additional regression analysis, I have described above my concerns with this analysis, with regards to the implications for reliability.

Q: What did you recommend to the Commission last year regarding Consumers' EJ analysis and investments?

A: I recommended that the Commission require the Company to delay rate increases for non-essential infrastructure investments until it had provided (1) a way for intervenors to access relevant Geographic Information System ("GIS") data, (2) a regression analysis as ordered by the Commission in Case U-21389,[206] and (3) a reliability analysis comparing reliability in EJ communities to likely situated non-EJ communities. I will further explain these recommendations, along with how the Company and the Commission responded to each of them below.

Q: How did the Commission and the Company respond to your request about GIS data?

A: In alignment with the Commission's Order in Case No. U-21389, I recommended that the Company develop a public map of Consumers' Geographic Information System ("GIS") data.[207] I argued that intervenors should have the opportunity to access and review GIS data so that they can adequately assess and verify the Company's claims regarding the success of their reliability investments in EJ communities.[208] The Commission agreed.[209]

[206] *In re Consumers Energy Co.*, MPSC Case No. U-21585, Cira-Reyes Direct Testimony (Nov. 5, 2024), at 5 TR 3509, lines 17–21.
[207] *Id*. at 5 TR 3504, lines 8–15.
[208] *Id*.
[209] U-21585 Order at 375.

I appreciate that the company created a public GIS data map in advance of this rate case.[210] However, the GIS data map is not user-friendly and therefore does not serve the purpose of allowing any intervenor or the public to understand easily the company's reliability data. When visiting the Company's online GIS data map, it is difficult to quickly identify which circuits serve EJ communities; reliability data is not clearly displayed and understandable; a user cannot do side-by-side comparison of performance between different circuits; map controls are not intuitive; and there is not a sufficient explanation of acronyms to describe what the map is illustrating.[211] This GIS data map is a good start, but it needs considerable improvement to be useful to intervenors and the general public.

Q: What action do you recommend the Commission take regarding the GIS data map?

A: I recommend that the Commission require Consumers to update the GIS data map's user interface to be easily navigable and understandable to any intervenor and member of the general public who wishes to view it. The website should include, at the very least, a key that explains any acronyms, intuitive map controls, and the ability to do side-by-side comparisons of performance between different circuits.

[210] Kelly Direct Testimony at 79, lines 5–15.
[211] *See* Ex. UCC-57, *MIEJ SAIDI and SAIFI Viewer*, EXPERIENCE.ARCGIS.COM, https://perma.cc/M5CN-XJF6 (last visited Sep. 21, 2025).

Q: How can Distributed Energy Resource ("DER") investment help EJ communities?

A: DERs are a more resilient form of energy, which means that more DERs in a community can help ensure that critical services remain open.[212] Thus, these additional resources are even more important for EJ communities that are already subject to greater harm when power outages occur.[213] Not only do DERs help prevent outages, they also provide benefits to the local community in "ratepayer cost savings, progress towards clean energy goals, local economic development," and longer-lasting infrastructure.[214]

Q: Is the Company prioritizing DER investment in EJ Communities?

A: I would like Consumers to provide more information on this. Witness Kelly mentions in his testimony that investment in DERs should be increased in communities that have the capacity to host these resources.[215] Specifically, Kelly cautions that DER studies should not be done in areas not suitable for DERs.[216] Kelly proposes that hosting capacity analysis ("HCA") will be necessary to determine where studies on DERs should take place.[217] Kelly defines HCA as "the amount of DERs that can be accommodated without adversely impacting operational criteria, such as power quality, reliability, and safety, under existing grid control and operations and without requiring infrastructure upgrades."[218]

[212] *In re Consumers Energy Co.*, MPSC Case No. U-20147, UCC Comments on the Company's EDIIP (Feb. 16, 2024) [hereinafter U-20147 UCC Comments], at 7.
[213] U-20147 EDIIP at 45.
[214] U-20147 UCC Comments at 11.
[215] Kelly Direct Testimony at 70, lines 19–21.
[216] *Id*.
[217] *Id*. at 70, lines 11–13.
[218] *Id*. at 70, lines 13–16.

I am concerned that EJ circuits, which would benefit most from DERs due to the greater impact of outages on EJ communities, may have low hosting capacity and, as a result, may be left behind in initial rounds of DER investment. Kelly's warning that DERs should only be tested in communities with the capacity to host them, while valuable, does not acknowledge the fact that the Company is the only entity responsible for grid upgrades. Communities that do not have hosting capacity were put in that position by prior failures to invest by the Company, and it is the Company's responsibility to ensure that upgrades are made quickly to ensure that those communities can realize the benefits of DERs.

Q: What has the Commission ordered regarding HCA analysis for EJ communities, and has the Company complied?

A: In Case No. U-21224, the Settlement Agreement "included a commitment by the Company to include data on hosting capacity in EJ communities in future filings."[219] The Company has partially complied. Up to this point, according to Company witness Kelly, the HCA conducted by the Company has "largely been limited to an initial 'go/no-go' analysis" conducted in 2021,[220] and the Company plans to do a detailed HCA by late 2025.[221] Thus, this analysis seems to be limited to "better study[ing] hosting capacity for EJ communities" to determine where DERs can be installed, instead of studying how to ensure that EJ communities have hosting capacity soon so that they do not get left behind while other communities start to reap the benefits of DER investment.[222]

[219] Kelly Direct Testimony, Ex. A-129 (MPK-19), at 50.
[220] *Id*.
[221] *Id.* at 71, lines 14–15.
[222] *Id*., Ex. A-129 (MPK-19), at 50.

Company witness McPhail introduced the DER Optimization Initiative, which will be workshopped in the coming years, which as the goal of implementing a system to integrate DERs into Consumers' distribution system.[223] McPhail's testimony neither indicates an explicit attention to EJ communities' heightened need for DERs, nor articulate a goal of prioritizing DER integration into communities that would benefit from DERs most.

The Company has also proposed to invest $30 million in EJ communities during the test year as part of its Vulnerable Communities Resiliency Plan, which will be part of a larger $600 million investment over several years.[224] Based on the $30 million in specific proposed investments in this case, the Vulnerable Communities Resiliency Plan appears to only include plans to invest in hardening to improve reliability and it does not include plans to improve hosting capacity and prepare EJ communities for DERs.[225]

Q: What is community solar, and how does it relate to DER investment?

A: Community solar is a solar project that is owned by and provides energy to members of the community in which the development is sited. By generating power right where it is used, community solar is a type of DER project, distributing power generation within the community itself.[226] Community solar programs have the potential to decrease energy burdens while accelerating the clean energy transition. They can reduce energy bills anywhere from 5 percent to 25 percent and are especially beneficial in EJ communities

[223] McPhail Direct Testimony at 72–73.
[224] Partlan Direct Testimony, Ex. A-167 (JMP-2), at 22; Kelly Direct Testimony at 73–74.
[225] *See* Partlan Direct Testimony, Ex. A-167 (JMP-2), at 22; Kelly Direct Testimony at 73, lines 9–23.
[226] Ex. UCC-58, *Solar Integration: Distributed Energy Resources and Microgrids,* U.S. DEP'T OF ENERGY (2025), https://perma.cc/8RN4-5D5W (last visited Sep. 21, 2025), at 2–3.

since they allow residents of multi-family housing units to access the benefits of solar energy.[227]

Q: What community solar programs does the Company currently have in place, and why is this a pertinent issue to this case?

A: In truth, the Company has no real community solar program to date; instead; the Company currently has a Solar Gardens program which allows customers to subscribe to "Solar Blocks," or the Company producing solar energy at solar power plants in Michigan.[228] The Company, through the Vulnerable Communities Resiliency Plan ("VCR Plan") has outlined the goal of "ensuring that no EJ circuits experience worse than industry average reliability."[229] Community solar, by virtue of being a DER project, can reduce the grid's vulnerability to outages at any one location and are not susceptible to short-run supply shocks like fuel shortages during natural disasters.[230] As such, a community solar plan would be a valuable tool in ensuring that the Company's goals in deploying the VCR Plan are realized.

I am aware the Commission will be considering community solar issues in Case No. U-21972, which is the Company's next VGP case, but it remains important to consider the impact of community solar on vulnerable communities, and its role in the success of the Company's proposed VCR Plan in this case.

[227] Ex. UCC-59, *Sharing the Sun Market Report Details Expansive Growth, Recent Trends In Community Solar*, NAT'L RENEWABLE ENERGY LAB'Y (Oct. 19, 2021), https://perma.cc/2FHV-QUNG at 2.
[228] Ex. UCC-60, *Solar Gardens*, CONSUMERS ENERGY, https://perma.cc/HS9T-RH3A (last visited Sep. 21, 2025), at 1.
[229] Myers Direct Testimony at 16, lines 22–23.
[230] Ex. UCC-61, KATY WAECHTER ET AL., NAT'L RENEWABLE ENERGY LAB'Y, TECHNICAL POTENTIAL AND MEANINGFUL BENEFITS OF COMMUNITY SOLAR IN THE UNITED STATES (2024), at 41.

Q: Why are investments in community solar important?

A: Community solar programs that are sited within EJ communities and that emphasize community involvement help ensure that EJ communities also share in the benefits from the transition to green energy, such as increased reliability of service and more sustainable energy production.[231] It is important that EJ communities have access to local community solar programs that can contribute to wealth creation and energy autonomy.[232] Community solar investors need to reside in the community where the solar development is sited. Community solar projects build ties within the community and increase community autonomy. It is important that community solar subscribers are compensated commensurately to distributed generation ("DG") customers so as not to disadvantage those who do not control their rooftops or do not have the same access to capital.

Q: What are your recommendations for the Commission regarding DER investment and community solar in this case?

A: The Commission should require Consumers to prioritize EJ communities in their HCA analysis and update EJ community grids quickly thereafter to ensure that EJ communities are also able to realize the benefits of early DER investment. The Commission should consider requiring both the DER Optimization Initiative and the Vulnerable Communities

[231] *See* Ex. UCC-62, ERIC SIPPERT, ENV'T L. AND POL'Y CTR., COMMUNITY-OWNED COMMUNITY SOLAR – OPPORTUNITIES AND CHALLENGES (2022) (available at https://perma.cc/EE3D-QLRQ), at 13.

[232] Ex. UCC-63, *Community Solar Basics*, U.S. DEP'T OF ENERGY, https://perma.cc/F8MG-FP6T (last visited Sep. 21, 2025), at 2; *see also* Ex. UCC-64, KATIE KIENBAUM ET AL., INST. FOR LOC. SELF-RELIANCE, ADVANTAGE LOCAL: WHY LOCAL ENERGY OWNERSHIP MATTERS (2023), at 6–8.

Resiliency Plan to adopt this goal as well. While I appreciate that the Vulnerable Communities Resiliency Plan proposes to do important hardening work, the Company should also be required to invest in increased hosting capacity in EJ communities as part of the Plan so that EJ communities can benefit from DERs as soon as possible.

VI. COMMUNITY ENGAGEMENT

Q: What are the differences among customer engagement, community engagement, and marketing?

A: Customer engagement is when a company representative engages one-on-one with a customer to "facilitat[e] program enrollment and product selection to meet customer [] needs."[233] This can include providing "vulnerable customers with information and enrollment in assistance programs."[234] Typically, these interactions are sales and service-oriented.

Community engagement is when an organization works to build lasting relationships to apply a collective vision that benefits the entire community.[235] It is an active method of implementing change in a community and can include educational programs and town hall meetings to raise awareness about what an organization is doing. In the utility context, this would look like Consumers engaging in two-way, collaborative communications with customers.

[233] Byrom Direct Testimony at 9, lines 4–5.
[234] *Id*. at 9, lines 6–7.
[235] Ex. UCC-65, Lee Samelson, *The Difference Between Community Engagement and Marketing*, CMTY. POWER (Feb. 16, 2016), https://www.communitypowermn.org/the_difference_between_community_engagement_and_marketing, at 1.

Companies engage in marketing and advertising to increase the profit they make from consumers through a positive brand or reputation in the community.[236] Marketing and advertising are one-way methods of disseminating information into a community through promotional materials.

While in practice, the lines among these categories can be blurred, it is still nonetheless useful to draw these distinctions. Whether a company has a service offering that meets a customer's needs will depend in part on whether it understands the characteristics and needs of the community of which the customer is a member, e.g., low- to moderate-income. Whether a customer service representative offers that service will color the customer's impression of the company, which will affect the company's reputation and what marketing the company will do. Regardless of these interactions, it is still useful to think about the differences among these terms because they illustrate the difference in the intent and focus of the company's efforts.

Q: Why should utilities engage in community engagement and outreach?

A: Effective community engagement and outreach provide customers and communities with the opportunity to actively engage with project and rate planning. This can lead to improved outcomes in initiatives taken by utilities, as customers are aware of any changes being made and can provide real-time feedback to ensure their needs are met.[237] In taking action that can affect community members, it is important for utilities to understand customers' experiences. Recognizing community needs and characteristics is

[236] *Id*.

[237] *See generally* Ex. UCC-66, LaTorria Sims et al., *Community Engagement: A Cornerstone of Environmental Justice*, RAMBOLL (Sep. 17, 2024), https://perma.cc/T96V-ZD3T, at 2–6.

essential for both creating a sense of ownership and commitment among customers and allowing for utilities to engage in informed decision-making to tailor strategies and interventions that best suit specific contexts.[238]

Q: How does Consumers describe its outreach in the community?

A: Consumers reports that its communications currently occur through various platforms such as on the energy assistance website, email, mail, robo-calls, social media, blog posts, flyers, press releases, interviews, and radio announcements.[239] Consumers notes that it continually revises communication materials and disseminates new programmatic updates to decrease confusion amongst customers in need.[240] To me, however, much of this is marketing and advertising, not true community engagement.

Q: How would you describe Consumers' engagement with EJ communities?

A: While Consumers has made efforts in the past to engage with EJ communities, it needs to do more to address their concerns directly about reliability, affordability, and equity. In my experience, Consumers has primarily communicated with members of the community through resource fairs, advertising campaigns, or sponsoring events. With regard to resource fairs, the Company sometimes provides information that is useful to customers, but there does not seem to be a clear way for customers to provide feedback, and it appears to me that often customers do not receive information on the programs that are most beneficial for them, as it is hidden among a wider array of less beneficial offerings.

[238] *See* Ex. UCC-67, Humberto Queiroz et al., *Understanding User Engagement and Needs in Energy Communities*, 2024 INT'L CONF. ON ENG'G, TECH., AND INNOVATION (2024), at 8.
[239] Ex. UCC-38 at 13.
[240] *Id*. at 12.

With regard to advertising campaigns and sponsoring events, the Company is trying to build a positive reputation but is not engaging with the community in a way that gathers information and is responsive to customer needs about reliability, affordability, and justice.

Q: In your experience, has Consumers solicited feedback from ratepayers?

A: In my experience, most of Consumers' communications with ratepayers are one-way, rather than two-way communications with customers for the purpose of soliciting feedback. As far as I am aware, Consumers has not hosted a forum in the community to gain insight from ratepayers in the area.

Q: How does the Company think of its functional engagement with customers?

A: Witness Byrom describes two major functions of the Customer Experience and Operations organization: Customer Interactions and Billing & Payment. "Customer Interactions ensures that customers are equipped to connect with the Company in their preferred channel . . . . Billing & Payment provides customers with accurate, punctual energy bills and consistent payment processes, and arranges personalized payment plans or settings . . . for individual customers."[241]

Consumers says it relies on its array of customer experience offerings to ensure customers are satisfied when interacting with the company. [242]

[241] Byrom Direct Testimony at 7, lines 5–11.
[242] *Id*. at 7, lines 12–15.

Q: What steps is Consumers proposing toward improving customer engagement?

A: Consumers is requesting $1.87 million in capital costs to support its LMI Customer Support Enhancement project, launched in December 2024.[243] The Company describes this project as supporting LMI customers by "driving greater awareness and enrollment into eligible programs and services . . . [by focusing] on four core functions: (1) Simplified Program Enrollment . . . (2) Proactive Communication and Programs Awareness . . . (3) New & Improved LMI Offerings . . . and (4) Continuous Improvement."[244] Since the program's launch, Witness Byrom claims that 55 percent of the 55,000 who have interacted with the tool are LMI customers.[245]

In addition to the LMI Customer Support Enhancement project, Consumers is projecting $2.88 million in operating and maintenance ("O&M") expenses for a test year ending April 30, 2027 that will go to Consumers Analytics and Outreach efforts.[246] Witness Byrom states that this funding will enable "the company to use its resources more efficiently, target communications to precise customer segments, and select programs that are most likely to provide customer value."[247]

Q: What could be beneficial about the LMI Customer Support Enhancement project?

A: Many of the goals of the project are laudable and needed. I agree with Witness Byrom that "LMI customers [need help] in reducing their utility bill expenses by driving greater awareness and enrollment into eligible programs and services[,] alleviat[ing] energy

[243] *Id*. at 25, lines 11–12.
[244] *Id*. at 25–26.
[245] *Id*. at 30, lines 1–2.
[246] *Id*. at 42, lines 1–2.
[247] *Id*. at 40, lines 20–22.

burden, reduc[ing] the risk of service disconnections due to unpaid bills, and [] ultimately improv[ing] household stability."[248] I support simplified program enrollment, appropriate proactive communications, improving program awareness, new and improved LMI offerings, and continuous improvement for the Company and its offerings based on feedback.[249] The Company states that "LMI customers account for more than 1 of every 3 customers in Consumers Energy's service territory; 11% are low income, meaning they are in crisis and unable to pay their energy bill; 25% are moderate income, commonly identified as being one crisis away from being able to pay their energy bill."[250] If these numbers are correct, then enhancements to improve customer service for LMI customers is critical.

Q: What are your concerns with the LMI Customer Support Enhancement project?

A: While the LMI Customer Support Enhancement project is a step in the right direction, I have several concerns. First, IT solutions are not the end-all, be-all; it is important that the Company has other methods of engaging customers and communities meaningfully about existing programs and offerings and additional or modified programs and offerings needed by customers and communities. Second, it is important that the Company continue to report on the successes and failures of these efforts so that the Commission, Commission staff, regular intervenors, and other interested persons can monitor the progress and ensure that continuous improvements are really taking place. Third, even after the adoption of the program, many members of the community have expressed

[248] *Id*. at 25, lines 19–23.
[249] *See id*. at 27, lines 9–19.
[250] *Id.* at 27-28.

difficulties in either contacting Consumers for information on affordability programs or reliability issues, and I have experienced a lack of proactive outreach from Consumers to LMI customers. Fourth, I believe that there is a lack of broad awareness of the Company's enhancements, and it would behoove the Company to engage more with those who work with LMI communities to get the word out about these improved processes.

In addition, I am concerned that Consumers is not planning to partner with environmental justice advocates in engaging with the community about the LMI Customer Support Enhancement Program, other Company efforts, and community needs. When identifying the community organizations that Consumers plans to collaborate with, the Company notes a variety of groups but do not mention environmental justice organizations.[251] Environmental justice groups work with community members who experience energy insecurity and have concerns over rate increases and can provide valuable insight into community concerns.

Q: What are your concerns with Analytics and Outreach?

A: Consumers states that their Analytics and Outreach efforts "allow the Company to more efficiently utilize its resources, target communications to precise customer segments, and select, develop, and implement programs that are most likely to provide customer value."[252] Consumers should provide information on how these Analytics and Outreach efforts directly benefit and engage with customers and how information received is

[251] Ex. UCC-45 at 3–4 (mentions Michigan 2-1-1; local nonprofits and human services agencies; faith-based organizations and community centers; food banks and housing assistance providers; educational institutions and workforce development programs; and health and human services agencies).
[252] Byrom Direct Testimony at 41, lines 19–22.

analyzed, responded to where appropriate, and meaningfully addressed when making decisions that affect customers. Fundamentally, I am concerned that these investments will be used for marketing and building the Company's brand, not for meeting customers' needs.

Q: What has your experience been in engaging with Consumers?

A: In my experience, Consumers has conducted outreach in the community through resource fairs, advertising campaigns, and as a sponsor for local events, which have not been effective as they could be in disseminating information on rate changes or assistance programs. For example, at the most recent Consumers sponsored event I attended, I observed that the Company's communications were mostly one-way, notifying customers about energy-saving initiatives such as energy-efficient lightbulbs rather than engaging with community members to solicit feedback on issues of energy affordability. The booth concerned with notifying customers about rate changes and assistance programs was not prominent, as it was difficult to find amongst the several other booths. At community events such as these, the Company should ensure that information on rate increases or assistance programs is prominently displayed to encourage engagement with community members.

Q: What actions do you recommend the Commission take regarding customer engagement, community engagement, and marketing in this case?

A: The Commission should order Consumers to include environmental justice organizations as partners in the LMI Customer Support Enhancement project. The inclusion of

environmental coalitions will bring attention to important environmental and energy justice issues.

The Commission should also require Consumers to host semi-annual town halls or focus groups with representative members of the community, and report annually the feedback that they have received from community members and how this feedback is incorporated into internal analyses. These efforts will provide more transparency into Consumers' communication with the community and the feedback that it has received as a result.

The Commission should also scrutinize closely categories like Analytics and Outreach to ensure that expenditures benefit customers and do not merely build the Company's reputation and brand.

Finally, the Company should report regularly to the Commission, intervenors and the public on the efficacy of the LMI Customer Enhancement Program.

VII. CORPORATE MEMBERSHIP RECOVERY

Q: How much has Consumers requested to recover for its corporate memberships?

A: Based on testimony and discovery, Consumers requests recovery for $830,705 in solely discretionary membership dues.[253] Consumers made no mention of any nondiscretionary corporate memberships, or costs associated with nondiscretionary memberships, in its application or testimony. But the Company indicated in discovery that it was not seeking to recover fees for any of its nondiscretionary memberships.[254] By discretionary, I am

[253] Ex. UCC-68, Consumers Electric's Response to UCC's First Discovery Request, U21870-UCC-CE-0236_ATT_1.
[254] Ex. UCC-69, Consumers Electric's Response to UCC's Third Discovery Request, U21870-UCC-CE-0688.

referring to those memberships for which a company has choice, whereas nondiscretionary memberships are typically mandatory.

Q: What information has Consumers provided about its corporate memberships?

A: The Company provided limited information about its corporate memberships. In direct testimony by Company Witness Matthew J. Foster,[255] witness Foster stated that "trade association dues and memberships" are included in the "Sustainability & External Affairs" area of Corporate Services[256] and that Edison Electric Institute (EEI) is a primary cost associated with the "Administration and Other" area of Consumers' Corporate Services.[257] Besides EEI, Witness Foster did not describe any other specific memberships or the costs associated with those memberships.

In response to discovery, Consumers provided that it pays discretionary dues for six organizations:[258]

1. Detroit Reg. Chamber of Commerce
2. Jackson Co. Chamber of Commerce
3. Keystone Policy Center
4. Michigan Chamber of Commerce
5. Michigan Electric and Gas Assoc. (MEGA)
6. Edison Electric Institute (EEI).

[255] Foster Direct Testimony at 4–5.
[256] *Id*. at 3–4.
[257] *Id*. at 5, lines 29–30.
[258] *See* Ex. UCC-68.

Its corporate membership dues for these organizations total $830,705.[259] Consumers also provided the fees for each of those organizations, with EEI being the largest at $770,775.[260] The Company also gave generic descriptions of the benefits and functions of each trade association: "working with the Michigan legislature," "best practices," "continued economic growth," and "research."[261]

None of the information provided in discovery was readily available in direct testimony. And using the Corporate Services O&M expenses data provided by Witness Foster, I could initially only estimate a maximum of $8,353 in corporate membership costs disclosed in the O&M expenses.[262] That number is just one percent of what Consumers is actually requesting to recover. This cost discrepancy is concerning because the Company has provided neither a sufficient description of the benefits and functions related to the $830,705 in trade membership dues and fees that the Company seeks to recover, nor a sufficient explanation for how these membership dues are accounted for in Corporate Services O&M expenses.

Q: Do the descriptions and discussions of customer benefits provided in Consumers' discovery responses justify ratepayer recovery of discretionary membership dues?

A: No. Consumers' lack of transparency and lack of sufficient explanation of each trade membership makes recovery unjustified. In addition to identifying specific customer benefits, Consumers should be required demonstrate how recovered dues are directly

[259] *Id*.
[260] *Id*.
[261] Ex. UCC-70, Consumers Electric's Response to UCC's First Discovery Request, U21870-UCC-CE-0236.
[262] Ex. UCC-71, SCR Workpaper 2; *see* Ex. UCC-70; *see also* Foster Direct Testimony, Ex. A-91 (MJF-2) at 1.

supporting ratepayer benefits rather than expenses that have no benefit or, worse yet, undermine ratepayer interests.

The Company's descriptions of benefits to customers are inadequate to justify recovery for these expenses. The Company lists "best practices," "continued economic growth," and "research" as some examples of the value these memberships provide customers.[263] These generic "descriptions" do not show clear, discernible benefits for customers.

One of the only tangible customer benefits that Consumers mentions—"Mutual Assistance coordination"[264]—is a component of EEI's Restore Power program, a completely voluntary program.[265] In other words, it is not a part of the core member services that EEI provides and is instead a separately funded activity that some member companies may "choose to pay for."[266] Fees for this program are capped at $15,000 and are calculated based on the number of customers a company has.[267] This cap of $15,000 is less than two percent of the more than $770,775 Consumers pays in membership fees to EEI. While I appreciate that Consumers has chosen to be in a mutual assistance initiative, I do not believe this voluntary program is enough to justify recovery for the entirety of EEI's membership costs.

The Company also presents membership information with insufficient clarity and detail. For example, the Company describes the Detroit Reg. Chamber of Commerce, the

[263] Ex. UCC-70.
[264] *Id.*
[265] Ex. UCC-72, *Issues & Policy: Reliability, Resilience & Emergency Response*, EDISON ELEC. INST., https://perma.cc/NNX9-SR9V (last visited Sep. 3, 2025), at 2.
[266] Ex. UCC-73, EDISON ELEC. INST., 2025 LOBBYING, ADVOCACY, AND OTHER EXPENDITURES (2025) (available at https://perma.cc/5A77-MJRR), at 5–6.
[267] *Id*. at 5.

Jackson Co. Chamber of Commerce, and Michigan Chamber of Commerce as one "Chamber of Commerce costs"[268] without any explanation of what that means for the Company or customers.

In addition, the Company offered no evidence in its initial case and has not provided any information through discovery to suggest that the recipients of membership dues spend those funds exclusively on services that directly benefit ratepayers. Consumers' EEI membership, for which the Company requests $770,775 in recovery, highlights this issue. In its 2023 tax filing, EEI disclosed $96.0 million in revenue,[269] from which $78.8 million came from membership dues.[270] EEI in that same year spent $28.9 million on executive compensation[271]— $5.6 million for its CEO alone.[272]

Moreover, how much, and even whether, Consumers uses EEI's services to directly benefit customers is wholly irrelevant to the calculation of Consumers' overall membership fee. In an April 2025 report, EEI disclosed that "the dues a company pays are a function of its average number of customers, total revenues attributed to its electric operations, and owned generating capacity."[273] EEI also publicly disclosed that its "Core Budget" involves primarily business and policy issues, including "employee salaries and benefits,"[274] with little to no clarity on how these business and policy issues could benefit customers.

[268] Ex. UCC-70.
[269] Ex. UCC-74, EDISON ELEC. INST., IRS FORM 990 (2023), at 13.
[270] *Id*. at 12.
[271] *Id*. at 13.
[272] *Id*. at 10.
[273] Ex. UCC-73, at 2.
[274] *Id*.

Ultimately, Consumers' requested recovery for all its corporate membership expenses is both unreasonable and unjustifiable, and the Company should be required to justify how its membership fees support organizational activities to the benefit of its customers in its direct testimony and application.

Q: Do any of the groups for which Consumers seeks recovery for its membership dues engage in political advocacy that undermines the interests of ratepayers?

A: Yes. EEI, "the association that represents all U.S. investor-owned electric companies,"[275] uses a substantial amount of its budget for advocacy that prioritizes the interests of companies rather than those of customers. In EEI's disclosures, the association engages with policymakers on member companies' behalf vis-à-vis "lobbying, advocacy, and regulatory proceedings."[276] EEI estimated that at least 14.1% of membership dues would be used for lobbying alone in 2025.[277] As EEI explains, their lobbying expenses include "federal lobbying and state-level lobbying," which target various environmental issues such as the Clean Electricity and Transmission Acceleration Act and the Ethics in Energy Act.[278] As I will elaborate on in the next section, EEI's political advocacy goes well beyond "lobbying" and is often counter to affordability, sustainability, and environmental justice, too.

Other organizations for which Consumers seeks to recover its membership dues from also engage in political advocacy. Both MEGA and the Michigan Chamber of

[275] Ex. UCC-75, *About EEI*, EDISON ELEC. INST., https://perma.cc/2VQ8-38DN (last visited Sep. 21, 2025), at 1.
[276] Ex. UCC-73 at 2.
[277] *Id*. at 3.
[278] *Id*.

Commerce, for which Consumers seeks to recover $11,066 and $34,084, respectively, almost exclusively serve as public policy forums for member organizations and engage with legislatures and policymakers on their behalf.[279] Consumers has offered no evidence that membership dues to these organizations provide tangible benefits for customers. For example, in the Company's discovery response, it stated that MEGA brought customers value through "working with the Michigan legislature" to "ensure safe, reliable and affordable electric utility service."[280] But Consumers did not provide any information about specific actions that MEGA has taken or give examples of when MEGA's work with the state legislature has promoted "safe, reliable or affordable electric utility service." Without more context, "working with the Michigan legislature," sounds to me like lobbying, for which the Company should not be able to recover. And in discussing the Chamber of Commerce memberships generally, Consumers could only point to "economic growth," connecting "with business customers," and supporting "community engagement" as general benefits.[281] Once again, however, Consumers failed to provide specific details such as *who* these business customers are and *what* community engagement opportunities they have supported. The only specific activities that have been confirmed by these organizations is political advocacy, and ratepayers should not be obligated to fund political advocacy.

[279] *See* Ex. UCC-76, *About MEGA*, MEGA, https://perma.cc/8D6P-9WHR (last visited Sep. 3, 2025), at 1–2; *see also* Ex. UCC-77, *Mission*, MICH. CHAMBER OF COMMERCE, https://perma.cc/PZ78-RTX8 (last visited Sep. 3, 2025), at 1; *see also* Ex. UCC-68.
[280] Ex. UCC-70.
[281] *Id*.

Q: How has recent political advocacy from EEI undermined the interests of ratepayers?

A: Since the 2000s, there have been several instances of EEI's political advocacy and activities running counter to the interests of ratepayers. Some notable examples include:

1. **Efforts to limit customer voices**: EEI has been a key resource for utilities who wish to fight municipalization campaigns, in which ratepayers seek to take control of the electric distribution system in their communities. In 2002, EEI published "New Public Power Takeovers: Strategic Resources for Defeating Municipalization" to guide companies through fighting "public power" initiatives.[282] The report identifies strategies like finding "natural" utility company allies *and* non-utility allies who do not "appear to be self-interested or motivated" as well as intensifying "advertising programs" to "nip the movement in the bud."[283] Guides like these identify municipalization campaigns as fraught with financial risk and as utility-enemy number one.
2. **Opposition to solar energy and net metering**: EEI has been a leading voice in opposition to net metering and rooftop solar, including because of the fear of decreased revenue.[284] In 2013, it issued its "Disruptive Challenges" report detailing the "financial risks" of distributed energy sources like community

[282] *See generally* Ex. UCC-78, EDISON ELEC. INST., NEW PUBLIC POWER TAKEOVERS: STRATEGIC RESOURCES FOR DEFEATING MUNICIPALIZATION (2002) (available at https://perma.cc/3ZFT-QYK9).
[283] Ex. UCC-78 at 6–8.
[284] *See generally* Ex. UCC-79, Gabe Elsner, *Utilities' Anti-Solar Campaign and Misinformation Debunked*, ENERGY AND POL'Y INST. (Mar. 19, 2015), https://perma.cc/C9LS-4EFE, at 2; Ex. UCC-80, Joby Warrick, *Utilities Wage Campaign Against Rooftop Solar*, THE WASH. POST (Mar. 7, 2015), https://perma.cc/AS54-MTZZ, at 1.

solar programs, spreading misinformation[285] These reports created fears of a "utility death spiral," which galvanized the utility industry into opposing rooftop solar.[286] And since 2015, EEI has launched a nationwide campaign against solar energy, pushing for increased fees and surcharges on net metering that would make solar panels unaffordable for many ratepayers across the country, despite these ratepayers' interests in owning clean and reliable sources of generation.[287]

3. **Anti-clean energy & climate regulations**: EEI has been a prominent critic of policies designed to reduce air pollution and greenhouse gas emissions from the power sector. In 2020, EEI hosted a political campaign training camp and identified climate policy as a major risk to the utility industry.[288] In a 2022 study on the climate rhetoric of major utility organizations, researchers found that, from 2000 to 2019, a representative sample of EEI documents focused more on pursuing "clean coal" and "carbon capture and storage" than "all other carbon-free technologies combined."[289] This indicates a consistent trend of promoting delayed action in the effort to stop climate change since the turn of the century. EEI "cast[s] doubt on climate change" through "disinformation

[285] Ex. UCC-81, William Pentland, *Disruptive Deceptions: How Electric Utilities Stifled Rooftop Solar*, FORBES (Dec. 4, 2015), https://perma.cc/35BG-JMCV, at 1.
[286] Ex. UCC-82, Hiroko Tabuchi, *Rooftop Solar Dims Under Pressure From Utility Lobbyists*, N.Y. TIMES (July 28, 2017), https://perma.cc/C3Q8-PHB7, at 4.
[287] Ex. UCC-80, at 3–4.
[288] Ex. UCC-83, David Pomerantz, *EEI Used Anti-Clean Energy Campaigns as Role Models in Political Boot Camp for Utility Execs*, ENERGY & POL'Y INST. (Aug. 27, 2020), https://perma.cc/8VYB-CU2Y, at 1–4.
[289] Ex. UCC-84, Emily L. Williams et al., *The American Electric Utility Industry's Role in Promoting Climate Denial, Doubt, and Delay*, 17 ENV'T RSCH. LETTERS Art. 094026 (2022), at 10.

campaigns" and "argue[s] for delayed action."[290] In 2024, EEI filed a lawsuit challenging the EPA's Clean Air Act Section 111 rules from April that year, which aimed at reducing greenhouse gas emissions from power plants.[291] Climate change increases the intensity of destructive weather events that take ratepayer lives, damage ratepayer property, and impose other significant costs on ratepayers individually and collectively.[292]

4. **Support for bailouts of uneconomic coal and nuclear plants:** EEI has recently supported efforts that would force ratepayers to subsidize coal and nuclear power plants facing economic hardship from increased competition from cheaper natural gas and renewable energy sources.[293] EEI has asserted that such plants are needed to foster reliability and resilience, but multiple energy trade associations have criticized these bailouts as costly, unnecessary, and contrary to clean energy goals *and* market principles.[294] These bailouts hurt ratepayers' access to sustainable and clean energy, not to mention their wallets.

5. **Support for Energy Security Plans that cost ratepayers millions:** In March 2025, EEI's Vice President of Business Operations and Regulatory Affairs testified against two bills in the Ohio State Legislature that aimed to eliminate

[290] *Id*.
[291] Ex. UCC-85, Kim Riley, *EEI Takes Targeted Strike at EPA's Power Plant Emissions Rule*, DAILY ENERGY INSIDER (May 22, 2024), https://perma.cc/JYK3-LZS4, at 1.
[292] *See generally* Ex. UCC-23.
[293] *See* Ex. UCC-86, Matt Kasper, *Coal and Utility Interests Ask for, Receive, Bailouts to Help Failing Power Plants*, ENERGY & POL'Y INST. (Oct. 2, 2017), https://perma.cc/K38V-64YL, at 4.
[294] *See* Ex. UCC-87, Gavin Bade, *FERC Seeks Fast Track on DOE Baseload Compensation Proposal*, UTIL. DIVE (Oct. 2, 2017), https://perma.cc/9ER9-QEMX, at 2–3.

Electric Security Plans (ESPs).[295] ESPs allowed utilities to facilitate bribes, bail out coal plants, and charge Ohio ratepayers an additional $3.7 billion since 2008.[296] The bills also sought to repeal a coal plant bailout that threatened to cost ratepayers up to $1 billion by 2030 and has already cost ratepayers $680 million.[297]

6. **Opposition to greater corporate transparency on emissions:** In 2024, EEI submitted a joint comment, along with the American Gas Association, urging the Securities and Exchange Commission (SEC) to significantly narrow and remove various requirements from its proposed rules regulating greenhouse gas emissions disclosures by public corporations.[298] Ratepayers repeatedly bear the full costs of climate change; they deserve to know which entities are emitting how much of which greenhouse gases that create those costs.

7. **Aiding utilities in litigation against regulators and public interest groups:** EEIs recent actions in the courthouse have run directly counter to ratepayers' interests in ensuring that utility companies comply with environmental and consumer protection laws. In recent years, EEI has joined lawsuits filed by utility companies that challenge state and federal regulatory decisions as an

[295] Ex. UCC-88, Dave Anderson, *Ohio's Big Utilities Fight Repeal of Scandal-Tainted Bill Riders that Cost Customers Billions of Dollars*, ENERGY & POL'Y INST. (Mar. 24, 2025), https://perma.cc/B5J7-8HMC, at 2.
[296] *Id*. at 4.
[297] *Id*. at 3.
[298] Ex. UCC-89, SEC Release Nos. 33-11042 and 34-94478, File No. S7-10-22 (June 17, 2022), at 5 (EDISON ELEC. INST. & AM. GAS ASS'N, Comment Letter on *The Enhancement and Standardization of Climate-Related Disclosure for Investors* (June 17, 2022), https://www.sec.gov/comments/s7-10-22/s71022-20131803-302239.pdf); *see also* Ex. UCC-90, *Scope 3 Inventory Guidance*, EPA, https://perma.cc/LZ5C-ZHHQ (last visited Sep. 21, 2025), at 1 (defining scope 3 emissions as those "that the organization indirectly affects in its value chain").

intervenor or amici curiae.[299] EEI also supports utility companies, and utility-friendly regulators, when they are in turn sued for alleged violations of various environmental and consumer protection laws.[300]

As these examples illustrate, EEI's advocacy and activities prioritize member companies' financial interests and shareholders, not the needs of ratepayers *or* the public at large. And this advocacy is subsidized by ratepayers through utilities' recovery of their membership dues, which are passed down to customers as higher rates.[301] Taken together, the most critical question is not whether EEI is valid in its campaigns and activities but whether such activities promote customer interests or shareholders' interests. The Commission need not take sides on debates regarding climate and energy to see that it is evident that EEI's advocacy is centered on financial outcomes for utility *shareholders* instead of benefits for ratepayers.

Q: Do you have any other concerns regarding the Company's funding EEI through rates?

A: Yes, I have free speech concerns. I do not support EEI's advocacy, whether through lobbying, filing lawsuits, testifying before legislators, or any of the other actions

[299] *See generally, e.g.*, Final Brief of Amicus Curiae Edison Electric Institute in Support of Petitioner, *Xcel Energy Servs. Inc. v. FERC*, 41 F.4th 548 (D.C. Cir. 2022) (advocating to reverse a FERC decision barring a vertically integrated grid operator from implementing rules to favor its own generators and thereby suppress market competition).

[300] *See generally, e.g.*, Motion of Edison Electric Institute for Leave to File Brief as Amici Curiae in Support of Defendants-Appellants, *N. Plains Res. Council v. U.S. Army Corps of Eng'rs*, 460 F.Supp. 3d 1030 (D. Mont. 2020) (seeking to argue for reversal of a lower court's ruling enjoining utility companies from discharging dredged or fill material into waterways in violation of federal law).

[301] *See* Ex. UCC-91, ENERGY & POL'Y INST., PAYING FOR UTILITY POLITICS: HOW RATEPAYERS ARE FORCED TO FUND THE EDISON ELECTRIC INSTITUTE AND OTHER POLITICAL ORGANIZATIONS (2017) (available at https://perma.cc/8TGM-2XG6), at 2.

discussed above. However, because Consumers is the only electric utility where I live, I have no choice but to either pay Consumers' rates and financially support advocacy that is harming my community and the communities I work to help, or to go without electricity at all. In other words, recovery for EEI's membership dues forces me to support EEI's policy positions, with which I do not agree. If the Company wants to fund EEI's operations, its shareholders should pay for those fees, but customers should not be compelled to pay for advocacy counter to their interests without their direct approval.

Q: Have other states' public utility/services commissions disallowed recovery for memberships with EEI or similar trade organizations that engage in political advocacy?

A: Yes. State PUCs from across the country have taken steps to limit or completely disallow fee recovery for trade associations that fund political advocacy:

1. **The Missouri Public Services Commission (PSC)**: More than forty years ago, the Missouri PSC established a standard that would allow recovery of fees for organizations that engage in political advocacy as long as the company could "include not only a direct quantifiable benefit to the ratepayer, but also a method of allocating the expenses between the shareholders and the ratepayers once the benefits have been quantified."[302] The Missouri Commission further clarified that it is not "necessary to discuss whether or not EEI is devoted primarily to lobbying, and the Missouri PSC justified this requirement by noting that "[i]t is obvious that the interests of the electric

[302] Ex. UCC-92, *In re Evergy Missouri West, Inc.*, Missouri PSC Case No. ER-2024-0189, Giacone Direct Testimony (June 27, 2024) (excerpted), at 4.

industry are not consistently the same as those of the ratepayers."[303] For the past forty years, utility companies in Missouri have failed to meet that standard, and no portion of EEI dues have been recovered since.[304]

2. **The Kentucky Public Service Commission (KPSC)**: In July 2021, the Kentucky Public Service Commission (KPSC) disallowed Kentucky Utilities (KU) from recovering any portion of its EEI membership dues. The KPSC established that utility companies have an "affirmative burden of proof" to show that "its proposed rates are fair, just and reasonable."[305] The Kentucky Commission justified its decision by noting that KU failed to meet its burden of proof because it could not identify how much of its EEI dues were spent on "regulatory advocacy and public relations."[306] It added that "a utility's mere incurrence of a cost," like trade associations dues, does not satisfy this burden or justify recovery.[307]

3. **The Oregon Public Utility Commission (OPUC)**: In October 2023, OPUC, in a rate case involving Avista Utilities, approved removing trade association dues after intervenors argued "that it is in the public interest for shareholders to shoulder political expenses that do not align with state policy or the public interest."[308] As a result, the Oregon Commission removed costs associated

[303] *Id*.
[304] *Id*.
[305] Ex. UCC-93, *In re Kentucky Utilities Co.*, Case No. 2020-00349, Order (June 30, 2021) (excerpted), at 3.
[306] *Id*. at 2–5.
[307] *Id*. at 4.
[308] Ex. UCC-94, *In re Avista Utilities*, PUC Docket No. UG 461, Order No. 23-384 (Oct. 26, 2023) (excerpted), at 3.

with the utility company's trade association dues in the 2023 rate case settlement.[309]

4. **The Arizona Corporation Commission (ACC)**: In March 2024, the ACC disallowed Arizona Public Service Company from recovering $1.1 million in EEI dues.[310] The Arizona Commission concluded that it was neither just nor reasonable to allow recovery for any of the APS' EEI dues.[311]
5. **The California Public Utilities Commission (CPUC)**: In 2019, the CPUC prevented utility company Southern California Edison (SCE) from passing more than 75% of approximately $1.9 million in EEI dues onto ratepayers.[312] The California Commission found that SCE "failed to present supporting evidence which would enable [the Commission] to determine how much EEI's beneficial services should cost ratepayers."[313]
6. **The Colorado Public Utilities Commission (PUC)**: The CPUC rejected Xcel Energy's request to recover over $775,000 in trade association dues altogether in 2024.[314] The decision followed the 2023 Colorado law that prohibits certain expenses, like trade association dues and lobbying fees, from being paid by customers.[315]

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[309] *Id*.
[310] Ex. UCC-95, *In re Arizona Public Service Co.*, ACC Docket No. E-0135A-22-0144, Order (Mar. 5, 2024) (excerpted), at 6.
[311] *Id*. at 5–6.
[312] Ex. UCC-96, Christian Roselund, *California Prevents Utility from Paying EEI Dues with Ratepayer Funds*, PV MAGAZINE (May 21, 2019), https://perma.cc/U26J-WVAP, at 3.
[313] *Id*.
[314] Ex. UCC-97, Mark Jaffe, *Xcel Ordered to Remove Investor Relations and Executive Salaries from Costs Passed on to Colorado Consumers*, THE COLO. SUN (Nov. 5, 2024), https://perma.cc/C86P-FP6J, at 2.
[315] *Id.*

Q: What actions do you recommend the Commission take in this case?

A: Based on what I've discussed above, I recommend the Commission take the following actions in this rate case:

1. The Commission should require Consumers to provide detailed descriptions of each of their corporate memberships in their future rate applications, which the Commission has already ordered another utility company, DTE Electric, to do.[316] In MPSC Case No. U-20836, the Commission ordered DTE to "file in its future rate cases an exhibit containing an itemized list of projected costs associated with membership fees and justification for why these costs are in customers' interests."[317] I would further argue that the Commission should require Consumers to explain (1) the tangible benefits customers gain through each organization and (2) how membership fees are allocated toward programs that support ratepayer interests.
2. Second, the Commission should disallow recovery for corporate memberships where there is no clear benefit to ratepayers and where a trade association directs a significant portion of membership dues to funding political advocacy. Disallowing recovery in those cases would help prevent ratepayers from inadvertently paying for activities that directly undermine their own interests, especially energy affordability.
3. Third, the Commission should specifically disallow recovery for Consumers' entirety of EEI's $770,775 membership fees given that the Company has not

[316] *See In re DTE Electric*, MPSC Case No. 20836, Order (Nov. 18, 2022), at 308.
[317] *Id.*

established any tangible benefits derived from this corporate membership and EEI's demonstrated track record of undermining ratepayer interests as a lobbying organization. To the extent that the Commission views "Mutual Assistance coordination" as a tangible benefit to customers, the Commission should disallow recovery for the entirety of the membership dues besides the voluntary payments under the Restore Power program that provide for this "benefit." The lack of transparency relating to where funds are being spent by EEI suggests that the Commission cannot find that recovery for these fees is just and reasonable.

Q: Does this conclude your written Direct Testimony?

A: Yes.

MR. TEMPLETON: Thank you, Your Honor.

Our second witness is Tabitha Williams, her written direct testimony consisted of one cover page and 32 pages of questions and answers. In that written direct testimony she sponsored Exhibits UCC-101 through UCC-112 inclusive and so at this time I moved to bind in Ms. Williams direct written testimony and her Exhibits UCC-101 through 112 inclusive.

THE COURT: Are there any objections to the admission to this testimony or these exhibits?

Hearing none. The direct testimony on Tabitha Williams is bound on the record and Exhibits UCC-101 through UCC-112 are admitted.

(At 3:22 p.m., Exhibits UCC-101 through UCC-112 are admitted)

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	))))))	Case No. U-21870 ALJ Jonathan F. Thoits

DIRECT TESTIMONY OF TABITHA WILLIAMS

ON BEHALF OF

URBAN CORE COLLECTIVE

September 30, 2025

I. INTRODUCTION

Q: Please state your name and occupation.

A: My name is Tabitha Williams. I am the founder and president of Parents for Healthy Homes, a volunteer organization that champions change through three pillars: education, involvement, and advocacy.

Q: Have you participated in any previous Michigan Public Service Commission (MPSC) proceedings?

A: No.

Q: What motivated you to found your organization, Parents for Healthy Homes?

A: I founded Parents for Healthy Homes in 2016 after I watched my five-year-old daughter suffer the impacts of environmental hazards such as lead in our home. As we navigated the harm to her health, I realized that there needed to be more proactive policies to protect children and families from environmental hazards in their homes. To address this, I founded Parents for Healthy Homes to organize other parents who wanted to ensure that all children are safe from the adverse health effects that various environmental hazards can cause.

Q: What is the mission of Parents for Healthy Homes?

A: Our mission is that all children will grow up free from environmental hazards in their homes and communities. Our vision is that all families can use their collective voice to

accomplish equitable change. We approach our goals through education, involvement, and advocacy, recognizing that whether the issue is energy justice or environmental justice, children are the most vulnerable, so they are at the heart of our work. Parents for Healthy Homes is a grassroots parent-led organization of volunteers, and we have lifted up the voices of the community collectively to address problems and shape systems in ways that meet families' needs.

Q: At what point did energy affordability become a formal part of your organization's work, and what prompted that expansion?

A: Energy affordability began to take a place in our organization when I saw how the high and rising utility costs were affecting families and children in harmful ways. High energy prices and constant rate increases force families to choose between basic needs like heating their homes and buying groceries, and parents find themselves unable to cope with high prices, especially while providing for their children. Advocating for energy affordability is part of advocating for healthier housing. Furthermore, energy affordability and clean energy are environmental justice issues that affect homes and families. Vulnerable communities and underserved communities are disproportionately impacted by the health effects of pollution, emissions, and climate change.[1] It was natural to integrate energy affordability advocacy into the organization's work because of how energy affordability is directly tied to environmental justice, especially in low-income or vulnerable communities like the ones in which we work. We recognize that safe homes

[1] *See generally* Ex. UCC-101, Jiawen Liu et al., *Disparities in Air Pollution Exposure in the United States by Race/Ethnicity and Income, 1990–2010*, 12 ENV'T. HEALTH PERSP. Art. 127005 (2021).

mean affordable homes, so affordable energy is intrinsically connected to our mission to support families holistically.

Q: Was there a specific moment when you realized energy affordability was such an important issue for the families you were working with?

A: I attended a community event hosted by True North, an organization that offered an energy payment assistance program at the time, and there were over fifty people just at this one event lined up, carrying their most recent energy bills, waiting to apply for payment assistance. I was one of those people, and I waited in line for a long time. The organization was only taking a certain number of people to be part of that program, so most people waiting in line could not sign up to receive assistance. I saw the way that the limited supply of payment assistance did not come close to addressing the need for assistance, and it was frustrating to see so many people turned away and left unable to pay their bills when affordable energy is absolutely necessary for safe and healthy conditions in each person's home. Seeing how many of us needed affordable energy and how few of us were able to receive assistance helped me realize that energy affordability is a key issue for not just myself but all the people and families that work with Parents for Healthy Homes.

Q: Can you share some examples of the community organizing work that you do with Parents for Healthy Homes?

A: We organize various educational, leadership-focused, and advocacy events that allow the community to learn and speak up about environmental hazards and energy justice issues. We are intentional about making sure that people understand these topics in settings where they feel comfortable and can build relationships with each other, and we shape our calendar based on the feedback of the community. We host frequent informal events, such as educational game nights and our annual Christmas mixer, to educate community members on environmental hazards and energy justice issues and to build trust and foster open discussion about the issues that matter to us. We often intentionally host social events in parks and social spaces in some of the most underserved areas in our communities to bring light back to those areas, as well as to show that these spaces are ours, that they deserve investment, and that we can make them safe and fun. On the first Monday of each month, we have our action meetings where we gather to discuss policy goals and plan to put them into action. We also host leadership trainings so that volunteers feel confident, educated, empowered, and ready to work, and we attend other community meetings and events to share our concerns. Most recently, we attended Lead Education Day and met with lawmakers to discuss the hazards of lead exposure and how to end lead poisoning in our homes.

Q: How long have you lived at your current address?

A: I have lived at my current address for over thirty years, and I have been a Consumers Energy customer during that entire time. My current address is 1128 Jefferson Ave. SE, Grand Rapids, Michigan 49507.

Q: What is the most important message from your testimony that you believe needs to be heard in this rate case?

A: Consumers Energy's bills are currently too high for many people to safely pay, even when engaging in various energy-saving measures that could actually be hazardous to people's health and safety. The complexity of energy bills means that many people do not understand what they are being charged for and are often not aware of the available options to make bills more affordable. Rate increases worsen the impacts of high energy bills on low-income and vulnerable populations who are already sacrificing their comfort, and sometimes their necessities, to ensure their bills are paid.

Additionally, outages and the fear of shutoffs pose significant risks for people, like my daughter, who have medical conditions, and low-income and vulnerable populations. The financial burden of these power outages is substantial, with losses that include spoiled food or medications that need to be refrigerated. The lack of clear communication and accessibility of payment assistance programs exacerbates the situation, leading people to rely on their communities and limited resources during outages.

Payment assistance programs are often unreliable and difficult to navigate due to inconsistent communication and a lack of proactive consumer outreach and engagement. The Company should be required to improve customer service accessibility, especially for those with disabilities or limited internet access, and engage in two-way communications with communities to better understand their needs.

Overall, the proposed rate increase would exacerbate energy insecurity for low-income families by making bills even more unaffordable. I recommend that Consumers Energy should automatically enroll all eligible customers in Winter Protection and bill assistance programs; provide meaningful customer service to ensure that customers are aware of all program assistance information; engage proactively with community leaders and organizations in low-income communities and communities of color; and focus on ensuring that current rates are affordable to expanded assistance programs and percentage-of-income payment plans.

Q: How have you organized your testimony?

A: I have organized my testimony as follows:

Part I: Introduction

Part II: Energy Affordability

Part III: Energy Reliability

Part IV: Payment Assistance Programs

Part V: Shutoffs and Winter Protections

Part VI: Customer Service and Accessibility

Part VII: Community Engagement

Part VIII: Impact of Proposed Rate Increases

Part IX: Recommendations

Q: Are you sponsoring any exhibits?

A: Yes. I am sponsoring the following exhibits:

UCC-101. Jiawen Liu et al., *Disparities in Air Pollution Exposure in the United States by Race/Ethnicity and Income, 1990–2010*, 12 ENV'T HEALTH PERSP. Art. 127005 (2021).

UCC-102. Tabitha Williams Consumers Energy Bill Statements (June, August, September 2025).

UCC-103. U.S. DEP'T OF ENERGY, BUILDING AMERICA CASE STUDY: TECHNOLOGY SOLUTIONS FOR EXISTING HOMES – A HOMEOWNER'S GUIDE TO WINDOW AIR CONDITIONER INSTALLATION FOR EFFICIENCY AND COMFORT (2013).

UCC-104. Abebe Hailemariam et al., *The Impact of Energy Poverty on Physical Violence*, 100 ENERGY ECON. Art. 105336 (2021).

UCC-105. *Consumer Outage History*, MICH. PUB. SERV. COMM'N (2025), https://perma.cc/Q3W4-XBCM (last visited Sep. 9, 2025).

UCC-106. Vivian Do et al., *Spatiotemporal Distribution of Power Outages with Climate Events and Social Vulnerability in the USA*, 14 NATURE COMMC'NS Art. 2470 (2023).

UCC-107. MED. SERV. ADMIN. AND MICH. DEP'T OF HEALTH AND HUM. SERVS., MSA 17-06 BULLETIN: EARLY REFILLS FOR PRESCRIPTION DRUGS (2017), (available at https://perma.cc/EC3F-2R25).

UCC-108. *Longer Term Assistance Programs*, CONSUMERS ENERGY (2025), https://perma.cc/3NJN-EVKM (last visited Sep. 19, 2025).

UCC-109. *State Emergency Relief (SER) Program*, MICH. DEP'T OF HEALTH & HUM. SERVS. (2025), https://perma.cc/M6K6-ZTPE (last visited Sep. 19, 2025).

UCC-110. *Payment Plans & Assistance*, CONSUMERS ENERGY (2025), https://perma.cc/YUG5-6J2V (last visited Sep. 19, 2025).

UCC-111. Consumer Energy's Response to UCC's Second Discovery Request, U21870-UCC-CE-0365.

UCC-112. Consumer Energy's Response to UCC's Second Discovery Request, U21870-UCC-CE-0376.

II. ENERGY AFFORDABILITY

Q: What was your most recent Consumers Energy bill amount?

A: Because I purchase both gas and electricity from Consumers Energy, I receive one combined bill. My most recent monthly bill amounts have been between $200 and $350.[2]

[2] Ex. UCC-102, Tabitha Williams Consumers Energy Bill Statements (June, August, September 2025).

Q: What percentage of your monthly income does your bill represent?

A: My bill costs me about 38 percent of my income, and because I live on a fixed income, I cannot change this percentage. This is incredibly difficult for me to afford, and I know that the energy bill takes up a large percentage of monthly income for a lot of people in my community. We try to reduce our energy usage as much as we can, but the bills still take up a large percentage of our income.

Q: How do you attempt to reduce energy use to manage costs?

A: First, we utilize shared spaces often to reduce the time spent in the home, since this reduces the amount of time that we must run the heater or air conditioning to keep the house at a safe temperature. In my house, we also share devices such as smartphones and laptops. We also keep the lights off as often as possible. When I am on video calls, I sit next to the window to use the natural light so that I don't have to turn the light on and use electricity. My lights are almost always turned off unless I need to turn the light on in a room for a very specific purpose. In the winter months, I was taught to use the oven to help heat the house, but I know it's not safe, so I try to avoid that as much as possible. I try to run all my appliances, such as my washing machine and dryer, on the same day each week to minimize using them. During the summer and winter, I keep my thermostat set at a certain temperature, even if everyone in the house feels cold or very hot. In the winter, I keep everyone in the house in one room to keep from having to heat the whole house, and we use blankets rather than turn up the thermostat.

In the summer heat, it takes a lot of energy to cool the house, but it's necessary to stay safe from heatstroke or other health effects. Most of us cannot afford central air conditioning, so we use window units to cool our houses, which are less efficient than central air conditioning.[3] We run our air conditioners as little as possible to use as little electricity as possible. We put up with a lot of discomfort in the summer to try to keep our energy bills down, but inevitably, we end up with high electricity bills in the summer.

Q: What is the most extreme measure you have seen families take to reduce their energy usage and bills?

A: Honestly, I have seen people stay in unhealthy relationships because they could not afford to move to a different place and pay their energy bills on their own.[4] I was in this situation for a long time; at least in part because of the high cost of energy, I could not afford to live alone. I see people often staying in relationships or in other harmful situations, making that sacrifice to make sure that they can afford to provide their children with basic necessities such as heating, cooling, medical necessities, and refrigeration.

In addition, my children have had to move back home at times because they could not afford their energy bills on their own. In Consumers Energy's service territory,

[3] Ex. UCC-103, U.S. DEP'T OF ENERGY, BUILDING AMERICA CASE STUDY: TECHNOLOGY SOLUTIONS FOR EXISTING HOMES – A HOMEOWNER'S GUIDE TO WINDOW AIR CONDITIONER INSTALLATION FOR EFFICIENCY AND COMFORT (2013), at 1.

[4] *See* Ex. UCC-104, Abebe Hailemariam et al., *The Impact of Energy Poverty on Physical Violence*, 100 ENERGY ECON. Art. 105336 (2021), at 2.

people are forced to make incredibly difficult sacrifices that affect their living situations and their mental health to afford electricity and meet their basic needs.

Q: How do you receive your bills from Consumers Energy?

A: I prefer to receive my bills by mail. I know that you can opt to receive the bills online, but I prefer to receive a paper copy of my bill in the mail because it allows me to visually process the charges and immediately call and ask questions about anything I don't understand. I find the online payment system much more confusing than the paper copy sent in the mail.

Q: When you receive a bill from Consumers Energy, do you find the charges easy to understand?

A: No, absolutely not. I have a really hard time understanding the charges on the bill; it isn't clear where all the different charges and fees come from. The bill breakdown does not make it clear how Consumers Energy calculates or assigns all the different surcharges. Because of this, it's hard to know which of the individual charges can be challenged, which charges may have mistakenly been assigned to me, and which charges will result in a shutoff if I do not pay them immediately. Because the bill is such a high percentage of my income, I have to make sure I prioritize the most urgent charges to make sure my electricity is not shut off before I can pay the rest.

III. ENERGY RELIABILITY

Q: How would you describe the reliability of Consumers Energy's electric service in your neighborhood and in the surrounding areas?

A: Consumers Energy's electric service is not reliable. We experience power outages often, and Consumers Energy is not efficient or effective at communicating the reason or the expected duration of the outage.[5] However, because Consumers Energy is the only energy provider in our area, community members do not have the option to pick another provider. I feel that Consumers Energy is providing basic electric service, but it is not working sufficiently to prevent or reduce outages.

Q: How frequently do you and others in your area experience power outages?

A: As of this testimony, I have experienced three power outages in the last year. That might not sound like a lot, but when you are on a fixed income, every outage represents a significant monetary cost and a major disruption to your life. When the power goes out, I am not able to keep food refrigerated, and so I lose all the food that I had purchased. During an outage, I am also unable to cook for myself and my family, so I must order food, which is expensive. Since I never know when an outage will happen, I also try to buy only a small amount of groceries at a time, so that if the power goes out, I will not lose an entire month's worth of food. However, buying small amounts of groceries multiple times a month is more expensive than buying groceries in bulk, so the unreliable

[5] *See* Ex. UCC-105, *Consumer Outage History*, MICH. PUB. SERV. COMM'N (2025), https://perma.cc/Q3W4-XBCM (last visited Sep. 9, 2025), at 1–3 (over this past year, as of Sep. 9, 2025, Consumers Energy has reported outage events for over 670,000 customers, not including outage events that affected less than 20,000 customers).

power service has the indirect impact of causing my monthly groceries to cost a larger portion of my monthly fixed income than it otherwise would. This is one example of how unreliable electric service impacts my entire life.

Power outages are also dangerous for people with medical conditions or certain health needs.[6] My daughter has severe asthma and relies on a nebulizer at times when her asthma is flaring up, and during a power outage, we cannot use that machine. Her medicine also needs to be refrigerated, and when the power goes out, I cannot keep her medicine cold. I have worried all through her life about what would happen if my daughter had a medical need while the power was out. I try to plan, but I am not able to prepare for the worst-case scenario. Each outage is a stressful and difficult experience.

For these reasons, I wish I had a generator, but I'm not able to afford one, and even if I could, I would not be able to maintain and operate a generator on my own. None of my close friends or family members has a generator either, so we don't have anywhere to go during a power outage.

Q: Typically, how much does each outage cost you?

A: Each time that the power goes out, if I have a full refrigerator and freezer with a month's worth of food, I lose between $300 and $400. I also lose the asthma medication in my refrigerator, which costs $200 per dose. In my experience, it is difficult to get Medicaid to cover replacements for these medications in the absence of a life-or-death situation.

[6] Ex. UCC-106, Vivian Do et al., *Spatiotemporal Distribution of Power Outages With Climate Events And Social Vulnerability in the USA*, 14 NATURE COMMC'NS Art. 2470 (2023), at 8–9.

While Medicaid may officially cover replacements in certain circumstances,[7] having to go through this process takes additional time and means additional calls and trips to the pharmacy.

Similarly, since I do not shop for groceries in bulk to avoid losing even more in food costs, I have to shop more frequently, which is not only more expensive but also means that I must spend more on gas for more frequent trips.

Q: Have you ever requested and/or received an outage credit? What was the process like?

A: To my knowledge, I have never received an outage credit. I am not aware of how to apply for an outage credit, since I have never received any communication from Consumers Energy about this. If I have received an outage credit, I have not seen the credit on my bill or been able to understand how the credit applied to my bill. An outage credit would be incredibly useful since it would help me recover at least some of the high cost of unexpected power outages.

Q: What do you do when you experience a power outage?

A: The first thing I do is reach out to my neighbors to see if any of them still have power, and if we have all lost power, we turn to other resources, such as local churches, for

[7] Ex. UCC-107, MED. SERV. ADMIN. AND MICH. DEP'T OF HEALTH AND HUM. SERVS., MSA 17-06 BULLETIN: EARLY REFILLS FOR PRESCRIPTION DRUGS (2017), (available at https://perma.cc/EC3F-2R25), at 1.

support. There are some community resources, but, for the most part, each person's support network is made up of their friends, family, and other people they know.

Personally, the first thing I do is try to save my food and my daughter's medicine from spoiling. I ask around to see who has power, and I try to get my food and my daughter's medicine there as fast as I can. Then I try to find people for my daughter and me to stay with. I always make sure my car has plenty of gas so that I can get us to someone who has power. During the COVID-19 pandemic, people were no longer able to go and stay with others during power outages, so I, along with many other community members, started to strategize other ways of getting by during power outages. In my garage, I have a deep freezer with ice in it, and during outages, I move as much as I can from the fridge to the deep freezer to use it as an ice chest, and I hope that the ice does not all melt before the power comes back on.

I also try to be proactive in planning for power outages. My family has a plan in place for what to do when a power outage occurs. My kids know who is responsible for packing up the perishable food, who is responsible for packing up the asthma medication, and who is loading necessities into the car. For us, planning for outages is like creating a fire escape plan so that we can make sure that everyone is safe and that we have what we need.

Q: When you experience a power outage, do you reach out to Consumers Energy?

A: During the power outage that happened last winter, I called the twenty-four-hour emergency phone number because I was very worried about being without power for a

long time during the winter. This number is not set up to respond to reports of power outages, but it was very cold, and I wanted to make sure that I was not without power for more than a few hours.

I used to call Consumers Energy to report power outages when they occurred, but I no longer feel that there is any point in reaching out. Every time I call, I listen to the same recorded message, which states that Consumers Energy is aware of the outage and lists a few generic and unhelpful safety tips. I was hardly ever able to speak with a person instead of listening to an automated message. Whenever the power goes out, I am already rushing to salvage food and supplies, so listening to a voice recording that does not share any useful information is not a beneficial use of limited time. Because of this, I no longer call to ask questions right away when the power goes out.

Sometimes, if the power is still out after a long time, I call Consumers Energy to see if I can get any information about what's going on. Usually, when I call, they tell me the cause of the outage, but they cannot tell me how long they expect the outage to last. Since calling is not helpful, most people I know do not spend time calling Consumers Energy; instead, we use that time to talk to our neighbors to see what we can salvage and where we can stay. We try to work together to make things work.

IV. PAYMENT ASSISTANCE PROGRAMS

Q: Do you currently, or have you in the past, participated in any of Consumers Energy's assistance programs?

A: I used to be enrolled in the Shutoff Protection Plan (SPP); my enrollment in that program recently ended. The purpose of the program was to make sure that I would not lose electric service during critical times. The Shutoff Protection Plan only protected me from shutoffs during certain months of the year; I was protected from shutoffs during the winter, but not during the spring, fall, or summer. To enroll in this program, I was surprised to learn that I had to pay a down payment of 10% of my total account balance, and that the shutoff protection would not start until I paid it.[8] If I could not afford the down payment, I effectively could not afford shutoff protection.

I am not currently enrolled in any other payment assistance programs, but I have applied for the Home Heating Credit and for State Emergency Relief through the Michigan Department of Health and Human Services. In the past, True North had helped me to enroll in the Consumers' Affordable Resource for Energy (CARE) Program. The CARE program is a twenty-four-month affordable payment program that offers customers a fixed, affordable monthly bill and pays down the customer's past-due balance as long as the customer continues to make regular monthly payments. While this program had funding, and while I was enrolled, it was very helpful in enabling me to afford my monthly energy bills. However, True North notified me that the program ran

[8] Ex. UCC-108, *Longer Term Assistance Programs*, CONSUMERS ENERGY (2025), https://perma.cc/3NJN-EVKM (last visited Sep. 19, 2025), at 2.

out of funding, and so I was not able to remain in the program after the twenty-four-month period ran out.

Q: Do you feel that Consumers Energy makes the costs, benefits, and government oversight of their payment assistance programs clear?

A: No, and it can feel like the lack of transparency is intentional. It is very difficult, if not impossible, to sign up for any of these programs directly with Consumers Energy; I have needed assistance from other organizations, such as True North, to sign up for payment assistance programs. We also do not receive clear communication when a program's funding ends, or when our enrollment in a program will end. I mostly hear about payment assistance programs at events like community fairs or through word of mouth. Most of this information is not made readily available by Consumers Energy outside of pages on their website.

Q: What do you think Consumers Energy fails to understand about their assistance programs?

A: I think that Consumers Energy fails to understand that having access to payment assistance makes a huge practical difference in people's lives. Energy affordability is a health and safety concern. People who cannot afford their energy programs have to choose between basic needs, such as food or medicine, and their energy. This is especially true for elderly people and people with health concerns. I do not think

Consumers Energy understands how vital affordable energy and accessible payment assistance programs are to people's ability to live a safe, healthy day-to-day life.

I also believe that Consumers Energy does not understand the generational effects of a lack of knowledge about assistance programs. Since I know how my parents mitigated their energy costs, that is the knowledge I use and will pass down to my children. Especially in communities where we do not know much about program assistance options, a lack of information can have long-term effects on our future generations while affecting how we are able to respond.

Q: In your opinion, what key features should a payment assistance program include?

A: Based on my experience, there are two key changes to Consumers Energy programs that I believe are necessary for their payment assistance programs to be useful to low-income people and families.

The first is to rearrange the administration of these programs such that they are reliable and easy to navigate. When a customer applies for these programs, they should have someone available to walk them through it and make sure they understand the terms, costs, and benefits of the program. Information about each program should also be available in several different forms—such as written hard copy including graphics, online and real-time assistance on the phone—so that people can comprehend what is being communicated in the way that works best for them. Consistent, clear and accessible communication like this would eliminate a lot of the barriers to enrollment.

Second, and most importantly, payment assistance programs must ensure that energy bills are actually affordable. This means that no customer should be paying an unreasonable percentage of their income toward their energy bills every month. According to my understanding, experts have determined that customers should be paying no more than 6% of their income on energy,[9] and Consumers' assistance programs should be designed to ensure that bills do not exceed that burden. This would ensure that families are able to afford energy and are not risking their health and safety or choosing between basic necessities because of energy bills that are simply too expensive for them to afford. The same price will not be affordable for everybody; the amount that people are able to safely pay for energy varies greatly, and Consumers Energy must take that into consideration when designing its payment assistance plans. At the end of the day, a payment assistance program does not work if it does not result in all customers having consistent access to affordable energy.

V. SHUTOFFS AND WINTER PROTECTION

Q: Have you ever received a shutoff notice or experienced a shutoff because you did not make a payment or were not able to make a payment on your bill?

A: I have experienced shutoffs before, but I have not had a shutoff since my daughter was diagnosed with asthma. Because of the severity of my daughter's medical needs—she requires consistent electricity for her medical equipment and maintaining healthy air

[9] *In re Consumers Energy Percent of Income Payment Plan*, MPSC Case No. U-21021, Consumers Energy Company's Percentage of Income Payment Plan Pilot Program Report (May 1, 2025), at 19.

quality—I would rather sacrifice paying for anything else than risk having our power shut off. However, I have received shutoff notices multiple times over the preceding years.

Through my work with Parents for Healthy Homes, I see this same pattern repeated across our community. Families receive shutoff notices during the worst possible time—October going into the winter months. This timing creates a perfect storm: summer cooling bills have accumulated, families have been making minimum payments to manage limited cash flow, and heating needs are beginning to increase just as energy becomes most essential for health and safety.

Q: Can you describe the shutoff notice process and what you have observed in your community work?

A: Once you miss a payment—for example, if you miss October—you receive the first notice in the following month's billing cycle. Immediately after that, you start receiving shutoff notices if you are unable to pay. In my experience, we receive these notices through mail or email; I do not believe I have been contacted via phone or text about a shutoff notice before. By then, we are entering the coldest months of December and January, when people get their power shut off.

The notices themselves add insult to injury. They arrive through the mail using color-coding that becomes more severe with each notice—starting with pink and progressing to bright red. These colored notices get affixed to your door, which means your neighbors and anyone passing by can see that you are struggling financially. In my community work, I consistently hear this same complaint from families—the utility will

make it very easy to reach you when they want payment, but when you are heading toward shutoff and might need help accessing assistance programs, there's no proactive outreach.

Q: What resources are available when people receive shutoff notices, and how accessible are they?

A: Most of the financial relief comes through programs like State Emergency Relief Program (SER),[10] but there is a timing problem. SER funding is released in October, which is when people start applying for assistance. However, by the time families are facing shutoff—which in my experience happens in the winter months of December and January—SER may not have any funding remaining.

This creates difficult situations for the families I work with. They must wait for help during the coldest part of the year when they have limited transportation options. For families like mine who are not comfortable with online applications, everything must be handled by phone, by paper, or in person. This means driving around in cold weather to organizations like the Salvation Army, trying to find assistance when you should be focused on staying warm and keeping your family safe.

Q: Are you familiar with Consumers Energy's Winter Protection Plan?

A: Yes, I was enrolled in what they call the shutoff protection plan. However, this protection only covers certain months—November 1st through March 31st—for customers who

[10] *See generally* Ex. UCC-109, *State Emergency Relief (SER) Program*, MICH. DEP'T OF HEALTH & HUM. SERVS. (2025), https://perma.cc/M6K6-ZTPE (last visited Sep. 19, 2025).

meet specific requirements like being over 65 or certain government benefits (e.g., Medicaid or food assistance programs).[11]

What I find problematic is that I had to apply for this protection. Through my community work, I have learned that many eligible families do not even know this protection exists. If Consumers Energy is legally prohibited from shutting off power to eligible customers during winter months, why must families know to request protection that should be automatic? The current system requires families to navigate bureaucracy and delays critical protections when they are most vulnerable.

Based on my experience helping families in crisis, Consumers Energy should automatically enroll all eligible customers in Winter Protection rather than requiring applications. Many families I work with do not know these protections exist until they are already facing a shutoff.

Q: Have you encountered consequences for missed payments beyond receiving shutoff notices?

A: Yes, and these consequences function as additional punishment for customers who are already struggling. If you miss a payment, Consumers Energy sometimes will not allow you to pay online or over the phone; you must go to a physical location to make your payment.

This happened to my elderly mother when she had a guardian. During the transition when her guardian was changed, there was a missed payment. When I took

[11] Ex. UCC-110, *Payment Plans & Assistance*, CONSUMERS ENERGY (2025), https://perma.cc/YUG5-6J2V (last visited Sep. 19, 2025), at 4–5.

over as her guardian, we could not call in or do it online because she had a returned payment. This also happened to my daughter when her bank changed and a payment did not go through. This policy disproportionately affects the families I serve—elderly residents, people with disabilities, and those without reliable transportation—creating additional barriers exactly when people need more flexibility, not less.

VI. CUSTOMER SERVICE AND ACCESSIBILITY

Q: How do you generally contact or interact with Consumers Energy, and what challenges do you face?

A: I primarily contact Consumers Energy by telephone because I need to be able to ask questions and get real-time responses to understand my options. However, Consumers Energy is not easily reachable by phone, and when I do connect with a representative, the process is often inadequate.

The shift toward primarily digital customer service creates barriers for much of my community: elderly residents, people with disabilities, families where English isn't the primary language, and those without reliable internet access. When I help families navigate utility issues through Parents for Healthy Homes, these barriers prevent them from accessing programs they qualify for.

Q: When you do reach Consumers Energy, how responsive are they to addressing complex situations?

A: Unfortunately, Consumers Energy's responsiveness is generally poor and inconsistent. My needs are almost never met with just one phone call. I am routinely transferred multiple times, put on hold for long periods, or told that someone needs to "look into" my situation and get back to me.

When I call, explaining that I cannot afford my payment and asking if there's a way to arrange a payment plan, they provide me with limited options. However, they typically do not ask about my income or other qualifying factors, and they do not explain why I am eligible for certain programs and not others. The fundamental problem is that if you do not know what programs exist, you cannot ask for appropriate help.

Q: Are there particular challenges for people with disabilities or other barriers to accessing information?

A: Yes, there are significant accessibility issues that Consumers Energy does not adequately address. Consider people with disabilities who cannot read proficiently or comprehend the information sent to them. There are many people in disabled communities—like my son with a cognitive disability—who would not be able to navigate online systems. He would need to speak with someone directly to understand what's being offered and to ask questions about his options.

However, that kind of personalized assistance is not consistently available, and these accessibility needs are not addressed in the literature they distribute. The people I

serve through my community work simply do not have enough information about available resources.

Q: Have you experienced miscommunication with Consumers Energy that affected your ability to access services?

A: Yes. About a year ago, I applied for an assistance program and received a denial letter. I was confused because I knew my income qualified me for help. When I followed up, I discovered that I had been denied not because I did not meet the financial requirements, but because I had not submitted a copy of my bill with my application.

No one had told me I needed to include my bill, and Consumers Energy should have had my billing information on file. This kind of miscommunication could easily prevent someone from getting the help they desperately need. My elderly mother would not have known how to navigate that kind of confusion, and my son, or others with disabilities, would not have understood what went wrong.

These communication failures have real consequences for the families I serve. If requirements were explained clearly from the beginning, families could easily provide what is needed instead of going through the stress and disappointment of denial.

VII. COMMUNITY ENGAGEMENT

Q: How often do Consumers Energy representatives engage with your community?

A: Consumers Energy has very little presence in our community. I invited them to participate in my annual Strong Family Celebration event because I wanted community members to learn about services they might not know about.

When they did come to our event, I was disappointed with what they offered. They focused primarily on weatherization services—things like energy-saving light bulbs and weatherproofing—rather than the assistance programs that people in our community really need to know about. The feedback I collected from community members confirmed this disconnect. They were talking about energy-saving measures when families needed to know about programs that would help them afford to pay their bills in the first place.

Q: What would meaningful community engagement look like from your perspective?

A: I need to be able to tell my community members about programs that will save them money each year, programs they can qualify for, and exactly what they need to do to be eligible. Consumers Energy should be proactively reaching out to communities like ours, especially communities of color and low-income areas where energy insecurity is highest.

Based on my community organizing experience, effective engagement means meeting people where they are, providing information in multiple languages, and ensuring that program representatives can answer detailed questions about eligibility and application processes. Consumers Energy's proposed methods of primary

communication, email and social media advertising,[12] fail to meet the threshold of effective engagement and providing people with two-way communication to have all of their questions answered.

Q: Has Consumers Energy ever asked you or your organization for feedback about their services or programs?

A: No, Consumers Energy has never proactively asked me for feedback about their services or programs, despite my role as a community leader who works with many families facing energy challenges. The only feedback opportunity they provide is the occasional customer service survey after phone calls.

Through Parents for Healthy Homes and my other community work, I see firsthand how people struggle with Consumers Energy's programs and services. I know what barriers prevent people from accessing help, and I know what would make their programs more effective. But I have never seen the Company show any interest in that kind of community input.

VIII. IMPACT OF PROPOSED RATE INCREASES

Q: What would a rate increase mean for the families you serve?

A: The families I work with through Parents for Healthy Homes are already choosing between utilities and food, utilities and medicine. A rate increase would push more

[12] Ex. UCC-111, Consumer Energy's Response to UCC's Second Discovery Request, U21870-UCC-CE-0365, at 2 (response (a)(iii)).

families into crisis and increase demand for emergency assistance that is already insufficient.

I would want the Commissioners to see and feel what the daily struggle is like for a family like mine just to keep the lights on. I would want them to feel the gut-wrenching pain in my stomach when I look at my daughter and feel hopeless about whether the lights will go out. I would want them to understand what it feels like to be trapped with an abuser, because you must choose between your safety and necessities, such as utilities and food. You're forced to make impossible decisions that no family should have to make.

When your child needs a $200 inhaler and you're facing a $200 utility bill, what do you think I'm going to choose? This is not just about numbers on a spreadsheet—this is about families who are struggling to survive, who are making impossible choices, and who are being failed by systems that should protect the most vulnerable members of our community.

Q: How would you describe the affordability of Consumers Energy's current rates?

A: Based on my community work, Consumers Energy's rates are already unaffordable for thousands of families. I regularly help families who are behind on their bills, facing shutoffs, and making impossible choices between utilities and other basic needs like food and medicine.

The utility acts like the monopoly it is. Families have no choice but to deal with Consumers Energy's high rates and poor service. As I tell people, it's not like Xfinity

where you can call around and shop around. When families get these bills, they have to deal with them, and many simply cannot afford what's being asked of them.

IX. RECOMMENDATIONS

Q: Based on your community work, what changes would help families in your community?

A: First, Consumers Energy should automatically enroll all eligible customers in Winter Protection and bill assistance programs rather than requiring applications. Many families don't know these programs exist until they are already in crisis. And the application process, often requiring the involvement of a third party, makes accessing the necessary programs far more difficult than it should be.

Second, the Company needs to provide meaningful customer service in multiple languages, with representatives trained to help people understand all available programs and assistance options. Many customers are not comfortable accessing all information online, and even then, the website does not provide the answers to all questions. Access to a representative is crucial for many families, and it could be the difference between maintaining power and facing a shutoff.

Third, Consumers Energy should engage proactively with community leaders and organizations in low-income communities and communities of color to ensure their programs actually reach the people who need them most. The Company vaguely describes some of the organizations it plans to collaborate with as "Local Nonprofits and

Human Service Agencies."[13] By not providing a more definitive list of organizations, primarily those that serve low-income communities and communities of color, it is possible that those people will be left out of receiving important information about their programs.

Finally, instead of raising rates on families who are already struggling, Consumers Energy should focus on making their current rates affordable through expanded assistance programs and percentage-of-income payment plans that ensure no family pays more than they can afford for this essential service.

Q: What would you want the Commission to understand about energy challenges in your community?

A: I would want the Commission to understand that energy is not a luxury—it's essential for health, safety, and dignity. The families I serve include children with asthma who need powered medical equipment, elderly residents who cannot survive without heat, and working families who are doing everything right but still cannot afford basic utilities.

Most importantly, I would want the Commissioners to understand that behind every rate increase, behind every policy decision, there are real families with real faces—children with asthma, elderly people who can't navigate complex phone systems, parents choosing between medicine and electricity. We are not just numbers in a rate case. We are your neighbors, and we deserve energy justice, not energy as a privilege that only some can afford.

[13] Ex. UCC-112, Consumer Energy's Response to UCC's Second Discovery Request, U21870-UCC-CE-0376, at 2–3 (response (d)(i)).

The question is not whether Michigan families deserve reliable, affordable energy. The question is whether you, the Commissioners, will use your power to make sure we get it.

Q: Does this conclude your written Direct Testimony?

A: Yes.

MR. TEMPLETON: Thank you, Your Honor. And for clarity for the record, Ms. Williams did not file any rebuttal testimony. Finally today we have two exhibits in the hearing room exhibits folder under UCC for today. The first UCC-201 is the company's response to UCC's fourth discovery request and the second exhibit UCC-202 is the MPSC staff report that was filed publicly in case U-20757. So I move for the admission of those two exhibits at this time.

THE COURT: Are there any objections to the admission of these exhibits?

Hearing none. Exhibits UCC-201 and 202 are admitted.

(At 3:23 p.m., Exhibits UCC-201 and 202 admitted)

MR. TEMPLETON: Thank you, Your Honor. I'll just note that we are planning to cross a witness Foster on Thursday, and we will likely have a couple of additional exhibits that we will have on the SharePoint at that time and will intend to move for the admission at that time. But that's all I have for you and everyone else today thank you, Your Honor.

THE COURT: Thank you. Is there anyone else present who wishes to bind in testimony.

MS. GILL: Your Honor. This is Celest Gill on behalf of the attorney general. I can bind in my

witness's testimony, as well as some exhibits and move across as well.

THE COURT: All right. Please proceed.

MS. GILL: Thank you. The Attorney General moves to bind in the direct testimony of Sebastian Coppola. There are two versions of testimony, confidential and public versions, and both consist of a cover page, a table of contents followed by a 185 pages of questions and answers. There was also an appendix A that was filed when Mr. Coppola was filed, that should also be bound into the record. Mr. Coppola sponsored pre filed exhibits AG-1 through AG-60 with exhibits AG-30, AG-32, AG-47, AG-48, AG-49, and AG-52 being confidential exhibits and the attorney general moves for the admission of those exhibits.

THE COURT: All right. Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct testimony of Sebastian Coppola is bound into the confidential record and Exhibit AG-1 through AG-29, AG-31, AG-33 through AG-46, AG-50, and AG-51 are bound into the public record and Exhibits AG-30 to 32, 47, 48, 49, and 52 are admitted to the confidential record.

(At 3:26 p.m., Exhibit AG-1 through AG-29, AG-31, AG-33 through AG-46, AG-50, and AG-51 are

bound into the public record and Exhibits AG-30 to 32, 47, 48, 49, and 52 are admitted to the confidential record).

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21870

In the matter of the application of	)
CONSUMERS ENERGY COMPANY	)
for authority to increase its rates for	)
the generation and distribution of	)
electricity and other relief	)

_____

PUBLIC

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of

Attorney General Dana Nessel

September 30, 2025

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Sebastian Coppola. I am an independent business consultant. My office is at 5928 Southgate Rd., Rochester, Michigan 48306.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. I have testified in several regulatory proceedings before the Michigan Public Service Commission (MPSC or Commission) and other regulatory jurisdictions. I have prepared and/or filed testimony in rate case proceedings, revenue decoupling reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power Supply Cost Recovery (PSCR) cases. As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, I have been intricately involved in regulatory proceedings related to gas cost recovery cases, gas purchase strategies, rate case filings and power plant cost analysis. I have also supported other witnesses in testimony before the MPSC in various rate setting and other regulatory proceedings.

Q. WHAT EXPERIENCE DO YOU HAVE WITH ELECTRIC UTILITIES?

A. I have performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, I have performed analysis of power costs and filed testimony in power supply cost recovery cases, including reconciliation of annual power supply costs.

In my position as Senior Vice President of Finance at MCN, I also had responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, I was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, I was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

Q. PLEASE LIST SOME OF THE MORE RECENT CASES YOU HAVE PARTICIPATED IN BEFORE THE MPSC AND OTHER REGULATORY AGENCIES.

A. Here is a partial list of the most recent regulatory cases in which I have participated:

- Filed testimony on behalf of the Michigan Attorney General in DTEE 2025 electric rate case U-21860 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2025-2026 GCR plan case No. U-21608.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-2024 GCR reconciliation in case No. U-21272.

- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 PSCR Plan Case No. U-21594.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2024 electric rate case U-21806 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2023-2024 GCR reconciliation in case No. U-21274.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 PSCR reconciliation in case No. U-21260.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR reconciliation in case No. U-21270.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan reconciliation in case No. U-21278.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21258.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2024 electric rate case U-21585 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2024 gas rate case U-21534 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Michigan Gas Utilities Corporation (MGUC) 2024 gas rate case U-21540 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2024 gas rate case U-21291 on several issues, including

sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2022-2023 GCR reconciliation case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in the Indian Michigan Power Company's 2023 electric rate case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 rate case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.

Appendix A elaborates further on my qualifications in the regulated energy field.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Michigan Department of Attorney General to perform an independent analysis of Consumers Energy Company's ("CECo" or the "Company") Electric Rate Case filing in Case No. U-21870. This testimony presents a report of that analysis with related recommendations.

Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?

A. I am addressing the following major topics in this case:

1. The level of proposed rate base and capital expenditures
2. Adjustments to depreciation expense and property taxes
3. The Company's cost of capital
4. The Company's working capital
5. The level of operations and maintenance expenses
6. The Company's proposed Service Restoration Resiliency Fund and Extraordinary Storm Accounting Proposals
7. The Deferral of Line Clearing Ramp Up Deferred Expense and the proper return on the deferred balance

The absence of a discussion of other matters in my testimony should not be taken as an indication that I agree with those aspects of CECo's rate case filing. The narrow focus of my testimony is, instead, a consequence of focusing on specific issues within the available resources.

Q. IS YOUR TESTIMONY ON THESE TOPICS ACCOMPANIED BY EXHIBITS?

A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under my direct supervision:

1. Exhibit AG-1 DR Response – Capex Dollars & Units at Subprogram
2. Exhibit AG-2 DR Response – Contractor Service Installation Costs
3. Exhibit AG-3 DR Response – Make Ready Asset Relocation Volumes
4. Exhibit AG-4 DR Response – LVD Lines Reliability Unit Costs
5. Exhibit AG-5 DR Response – Undergrounding Pilot Results
6. Exhibit AG-6 DR Response – Premature LVD Projects
7. Exhibit AG-7 DR Response – LVD Line Capacity Percent Overload
8. Exhibit AG-8 DR Response – Transformer Volume and Cost Increases
9. Exhibit AG-9 AG Calculation of Transformer Cost Disallowances
10. Exhibit AG-10 DR Response –Repetitive Outages
11. Exhibit AG-11 DR Response – LVD Substation Capacity Activity
12. Exhibit AG-12 DR Response – HVD Red Tagged Pole Replacement
13. Exhibit AG-13 DR Response – HVD Substation Reliability Projects
14. Exhibit AG-14 DR Response – HVD Premature Projects
15. Exhibit AG-15 DR Response – Strategic Customer Projects
16. Exhibit AG-16 DR Response – Circuit Modernisation Activity
17. Exhibit AG-17 DR Response – Asset Repository System Development
18. Exhibit AG-18 DR Response – Covert Power Plant Projects
19. Exhibit AG-19 DR Response – Ludington Upgrade Projects
20. Exhibit AG-20 DR Response –Campbell Plant Operation Revenue Credits
21. Exhibit AG-21 DR Response – Generation Premature Projects
22. Exhibit AG-22 DR Response – Control/Dispatch Centers & Consolidation
23. Exhibit AG-23 DR Response – Facilities Emergent Repairs
24. Exhibit AG-24 DR Response – Transportation Fleet Expanded Purchases
25. Exhibit AG-25 AG Recalculation of Fleet Purchases and Costs
26. Exhibit AG-26 DR Response – Fleet Utilization Inactive Vehicles
27. Exhibit AG-27 DR Response – IT Premature Projects – Group 1

28. Exhibit AG-28 AG Calculation of Disallowances for Premature IT Projects
29. Exhibit AG-29 DR Response – IT Premature Projects – Group 2
30. Exhibit AG-30 CONF DR Response – SAP S/4 HANA Project Phase
31. Exhibit AG-31 DR Response – ARP Field Devise Asset Management
32. Exhibit AG-32 CONF Summary Cap Ex, Rate Base, Depreciation & Tax Expense
33. Exhibit AG-33 Working Capital Adjustments Summary
34. Exhibit AG-34 CECo Cash on Hand balances and Calculation
35. Exhibit AG-35 Overall Cost of Capital
36. Exhibit AG-36 Cost of Equity Capital
37. Exhibit AG-37 Cost of Common Equity-DCF
38. Exhibit AG-38 Cost of Common Equity-CAPM
39. Exhibit AG-39 Cost of Common Equity-Risk Premium
40. Exhibit AG-40 ROE Decisions by Regulatory Commissions
41. Exhibit AG-41 Peer Group ROE Decisions
42. Exhibit AG-42 Peer Group Selection Screening
43. Exhibit AG-43 Market to Book Ratios
44. Exhibit AG-44 Pro-Forma Cash Flow Coverage Ratios
45. Exhibit AG-45 Stock Market Historical Returns
46. Exhibit AG-46 Stock Market Forecasted Return
47. Exhibit AG-47 CONF DR Response – Moody's May 29, 2025 Report
48. Exhibit AG-48 CONF DR Response – S&P August 26, 2024 Report
49. Exhibit AG-49 CONF DR Response – Fitch Investor Service April 16, 2024 Report
50. Exhibit AG-50 DR Response – Blue Chip Treasury Rate Report
51. Exhibit AG-51 Values Line Report on Market Volatility vs. Risk
52. Exhibit AG-52 CONF RRA Report and Attachment
53. Exhibit AG-53 O&M Adjustments - Summary
54. Exhibit AG-54 Distribution O&M Adjustments
55. Exhibit AG-55 Service Restoration Cost Adjustment
56. Exhibit AG-56 Staking & Locating O&M Adjustments
57. Exhibit AG-57 DR Response – Staking and Locating Costs

58. Exhibit AG-58 AG Revenue Deficiency Calculation
59. Exhibit AG-59 Return Calculation on Deferred Line Clearing Costs
60. Exhibit AG-60 Incentive Compensation Actual Performance for five years

II. SUMMARY CONCLUSIONS & RECOMMENDATIONS

Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND ANY ADJUSTMENTS TO THE COMPANY'S REVENUE DEFICIENCY CALCULATION BEFORE YOU ADDRESS EACH TOPIC IN DETAIL.

A. The Company filed for a rate increase of $436 million. The rate increase represents an overall increase in rates of 9.7% and an increase of 13.3% to residential rates.

Based on my analysis, I have identified several cost disallowances to the Company's proposed cost levels and capital projects, which I recommend that the Commission adopt. As a result of these adjustments, I have determined that the Company has a revenue deficiency of $157.7 million at most, which represents an overall increase in rates of 3.5%. My conclusions and related adjustments are summarized below:

1. I recommend a reduction in capital expenditures of $877 million and a reduction of $679.1 million to rate base for the test year, including a $74 million reduction to working capital. This reduces the Company's revenue deficiency by $55 million.

2. I recommend that the Commission adopt a lower cost of capital rate of 6.06%, a capital structure with 50% equity capital and a return on common equity of 9.80%. These recommendations reduce the Company's revenue deficiency by $59.3 million.

3. I recommend a lower level of Operations and Maintenance expenses for the test year. This reduces the Company's revenue deficiency by $137.9 million.

4. I recommend a lower amount of depreciation expense of $28 million pertaining to the lower capital expenditures and additions to plant discussed above. This adjustment reduces revenue deficiency by the same amount.

5. I recommend a lower amount of property tax expense of $4.0 million pertaining to the lower capital additions to plant discussed above. This adjustment reduces revenue deficiency by the same amount.

6. I recommend that the Commission not adopt the Company's proposal of the Service Restoration Resiliency Fund or the Extraordinary Storm Accounting procedure and instead open a generic docket to study proposals on storm restoration recovery mechanisms.

7. I recommend that the Commission approve the deferral of costs from the Line Clearing Ramp-Up and set a baseline equal to the 2024 expense.

8. I recommend that the Commission approve a return on the deferred regulatory asset balance no higher than the short-term interest rate approved in this case and updated in each case thereafter.

III. CAPITAL EXPENDITURES AND RATE BASE

Q. WHAT ARE YOUR FINDINGS IN ANALYZING THE COMPANY'S PROPOSED LEVEL OF CAPITAL EXPENDITURES ADDED TO RATE BASE?

A. The Company is continuing the major ramp up of capital expenditures in a variety of areas. In this case, CECo reported capital expenditures of $1.2 billion for 2024 and forecasts capital spending of $2.0 billion for the 16 months bridge period ending April 2026, and an

additional $1.9 billion for the 12 months ending April 2027.[1] These amounts totaling to $5.1 billion are in addition to capital expenditures of $5.7 billion made during the prior five years from 2019 to 2023.[2]

In the Electric Distribution area in this rate case, the Company is requesting approval for $3.9 billion in capital expenditures for the 28 months from January 2025 to April 2027.[3] In comparison, in the last electric rate case (Case No. U-21585), the Company requested approval of $2.3 billion in the Electric Distribution for the 26 months ending February 2026.[4] The requested capital spending in this rate case represents a 70% increase over that case. The Company attempts to justify the increased spending by pointing to the implementation of the Reliability Roadmap investment plan it filed in June 2025 and included in this rate case as Exhibit A-129 (MPK-19).

Cost increases related to capital spending from return on investment, depreciation expense, property taxes, and O&M expenses make up $172 million, or 37%, of the requested rate increase of $460 million in this rate case.[5] The compounding effect of large additions to rate base will continue to increase customer rates to a level that is unaffordable for many customers, particularly lower income customers. This trend is not sustainable for customers.

[1] Exhibit A-12, Schedule B5.
[2] Exhibit A-12, Schedule B-5 in MPSC Case Nos. U-20963, U-20697, U-21224, U-21389, and U-21585.
[3] Exhibit A-12, Schedule B5.
[4] Case No. U-21389, Exhibit A-12, Schedule B5.
[5] Heidi Myers direct testimony at page 5.

Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE CAPITAL EXPENDITURES COULD BE REDUCED?

A. Yes. I analyzed the Company's forecasted capital expenditures by specific program, projects, or capital spending category, and I have identified more reasonable and prudent expenditure levels that the Commission should consider. In my analysis, I will often use recent historical actual costs and unit costs, where applicable, to determine the reasonableness of the Company's forecasted costs. This approach normalizes various costs from year to year and reflects the most recent costs experienced by the Company.

To provide some allowance for future increases in costs, I apply an inflation escalator of 2.1% for 2025, 2.4% for 2026, and 2.4% for 2027 in forecasting future capital expenditures where applicable. These inflation rates were provided by the Company in WP-PDD-37 and are used in its own inflation adjustments. Using these rates, I developed prorated inflation rates of 2.9% for the 16 months bridge period ending April 2026 and 2.4% for the projected test year ending April 2027.

A. Electric Distribution Capital Expenditures

As shown in Exhibit A-12 (MPK-1), Schedule B-5.6, the Company incurred capital expenditures of $920.4 million for Electric Distribution plant in 2024. It forecasted $1.598 Billion for the 16-month bridge period ending April 2026 and $1.530 Billion for the projected test year ending April 2027. Included in these total amounts are capital expenditures for New Business, Reliability programs, Capacity expansions, Demand

Failures upgrades, Asset Relocation projects, and Other Electric Operations. In my testimony below, I will evaluate and propose adjustments to several of these programs, subprograms, and component projects.

In their testimony and accompanying exhibits, Company witnesses Megan Heyward and Jennifer Partlan present forecasted capital expenditures in two major categories in line with the design of its distribution system, consisting of High Voltage Distribution (HVD) and Low Voltage Distribution (LVD) facilities. Witnesses Michael Kelly and Scott McPhail also provided testimony on certain topics to which I will respond or will recommend cost disallowances.

Q. DO YOU HAVE ANY OBSERVATIONS ABOUT THE CAPITAL EXPENDITURES INFORMATION PRESENTED BY MS. HAYWARD AND MS. PARTLAND IN THEIR TESTIMONY, EXHIBITS, AND RESPONSES TO DISCOVERY?

A. Yes. In total, the four witnesses identified above filed more than 600 pages of testimony describing individual capital programs within the Electric Distribution area, plus hundreds of pages of exhibits. In Exhibit A-113 (MPK-3), Mr. Kelly sponsored the combined HVD and LVD capital expenditures for the historical five years 2020-2024 and the projected periods with a variance column at the capital program and sub-program level. In Exhibit A-130 (MPK-20), Mr. Kelly provided the capital expenditures for the five historical years 2020-2024 at the sub-program level with the related number of units and unit costs. In

response to discovery, the Company expanded this exhibit to include forecasted capital expenditures, the number of units, and the unit cost for the bridge period and the projected test year. This expanded information is included in Exhibit AG-1 and I will refer to it from time to time when analyzing sub-program level capital expenditures and related units and unit costs.

In their testimony, Ms. Hayward and Ms. Partlan provide forecasted capital expenditures at both the program and subprogram levels with the number of units and some unit costs for the bridge period and projected test year. Additionally, those witnesses sponsored Exhibits A-109 (MLH-3), A-110 (MLH-4), A-166 (JMP-1) and A-167(JMP-2) showing individual projects and related expenditures within capital programs.

Although Ms. Hayward and Ms. Patlan dismiss the applicability of unit costs to assess the reasonableness of historical and forecasted capital expenditures for most programs, I find this information useful. The alternative would be to review the individual project cost workup and engineering cost estimates prepared by the Company for thousands of projects. Such an approach would require unlimited resources, would be prohibitively expensive, and impossible to achieve within the 10-month timeframe of a rate case.

In my analysis below, I will rely heavily on the information presented in the exhibits identified above along with information provided in the testimony of Ms. Hayward and Ms. Partlan, and responses to discovery requests.

1. LVD Lines New Service Connections

On line 1 of Exhibit A-113 (MPK-3), the Company shows actual capital expenditures of $116,118,000 for the year 2024 for Lines New Business to build new LVD lines for residential and small commercial customers. It also forecasted expenditures of $168,047,000 for the 16-month bridge period ending April 2026, and $130,200,000 for the projected test year ending April 2027. Exhibit AG-1 on line 2 of the attachment provided by the Company shows this information plus the number of units and unit costs for the historical and projected period.

Beginning on page 8 of her direct testimony Ms. Parlan discusses this program and presents the number of new service lines, unit costs, and capital expenditures for the historical years, the bridge period and the projected test year.

After evaluating the historical number of new service lines recently installed and recent economic trends, I find the Company's forecasted units of 12,211 for the 16-month bridge period and 9,252 for the projected test year to be reasonable. However, I find the unit cost forecasted for the bridge period and the projected test year to be excessive relative the average cost during the most recent historical year. The cost per unit in 2024 was $12,971, which was lower than the pervious two years. In contrast, the Company forecasted unit costs of $13,762 for the bridge period and $14,073 for the projected test year.

In discovery, the Attorney General asked the Company to explain the decline in the unit cost in 2024 and how it determined the unit costs for the bridge period and projected test

year. Regarding the forecasted unit costs, the Company stated that it used an extrapolation of historical costs to forecast both cost and units but could not provide a calculation. Regarding the decline in the unit cost in 2024, the Company reported that it has taken a cross-functional unit cost reduction effort and by placing more focus on detailed design reviews, improving labor planning and materials availability, among other efforts, was able to reduce the service installation costs in 2024.[6]

It is reasonable to assume that the unit cost reductions achieved in 2024 will continue into the bridge period and projected test year with appropriate future inflation adjustments. Using the 2024 unit cost of $12,971, I applied the inflation rate of 2.9% for the 16 months in the bridge period to arrive at a forecasted unit cost of $13,347. I multiplied this cost by the 12,211 units provided by the Company to forecast capital expenditures of $162,980,000 for the bridge period. This amount is $5,067,000 lower than the $168,047,000 forecasted by the Company.

Similarly, for the projected test year, I applied the inflation rate of 2.4% to the bridge period forecasted unit cost to arrive at a unit cost of $13,667.[7] This amount multiplied by the 9,252 units forecasted by the Company results in forecasted capital expenditures of $126,447,000. This amount is $3,753,000 lower than the Company's forecast of $130,200,000.

[6] Exhibit AG-2 includes DR AG-CE-0335.
[7] $13,347 x 1.024 = $13,667.

Therefore, I recommend that the Commission remove $5,067,000 for the bridge period and $3,753,000 for the projected test year from the Company's forecasted capital expenditures.

Q. ARE THERE OTHER ISSUES YOU WISH TO DISCUSS REGARDING THE COST OF INSTALLATION OF NEW SERVICE LINES?

A. Yes. On page 15 of her direct testimony, Ms. Partland addresses the Commission directive in Case No. U-21585 that the Company present comparative unit cost of new service line installations performed by Company employees versus the unit cost for installations done by contractors. The comparison in Figure 7 of Ms. Partland's direct testimony shows that in 2020 the cost of installation was nearly the same between Company-completed units versus contractor installation. However, the two began to diverge in 2021 reaching a large difference in 2023, whereby the cost of contractor installed service lines was more than twice the cost of Company's installations.

Although the large difference narrowed somewhat in 2024, it remains at more than $9,000 or 75% higher for contractor installations. In response to discovery, the Company could not provide a forecast of where this cost differential will be in 2025 and the next two years. It also claims that part of the cost difference is that the contractor costs are fully loaded with third party services and the Company's costs may not be.[8] The Company provided no evidence to support that claim and it is not clear why Ms. Partland would make that

[8] Id. Includes DR AG-CE-0335

statement when page 1 of Exhibit A-112 (MPK-2) shows that New Business Program costs include Loadings and Chargebacks for Company installations in addition to labor, materials, and contractor costs. It seems reasonable to assume that the same cost allocation practices used now also existed in 2020 and 2021 when the unit cost difference was much smaller.

My conclusion is that the Company still needs to do more to bring contractor costs in line with internal cost of installation. If significant further reductions from contractors are not possible, the Company needs to shift even more work in-house. I recommend that the Commission direct the Company to present a clear plan for how it will achieve further cost reductions for the installation of new service lines in the next rate case.

2. LVD Asset Relocations

On line 38 of Exhibit A-113 (MPK-3), the Company shows forecasted expenditures for LVD Lines Demand Failures of $97,911,000 for the 16-month bridge period ending April 2026 and $79,090,000 for the projected test year ending April 2027. Ms. Partlan discusses this subprogram beginning on page 27 of her direct testimony. On page 35 and Figure 16 of her testimony, Ms. Partland shows the three major components of this program. I will address two of the components, the Customer Requested and Other Internal Relocations, and the Make-Ready Work.

Customer Requested and Other Internal Relocations require the relocation of electric poles and lines along with other related items. Customer requests for relocations occur

throughout the year and are not fully known to the Company when preparing the capital expenditures for the forecasted periods. As shown in Figure 16, the Company forecasted 4,163 work units for the bride periods and 3,379 units for the projected test year. In Exhibit A-166, the Company shows only 1,828 known projects for the bridge period and in Exhibit A-167 only 1,185 projects for the projected test year. Based on the information provided in Exhibit A-130, line 38, for the three historical years 2022 to 2024, the Company had 2,369 relocations per year on average. The total forecasted number of units for the bridge period and projected test year are excessive relative to historical levels and known projects. Ms. Partlan provides no justification for the large increase in forecasted units in her testimony.

Absent any justification for the forecasted increase in the number of work units, I used the historical average annual number of units of 2,369 for the last three years as a basis to calculate a reasonable capital expenditures forecast. For the bridge period, I calculated 3,159 units (2,369 x 16/12) and using the Company's forecasted unit cost of $10,814 determined a capital expenditures amount of $34,161,000.[9] This amount is $10,857,000 lower than the Company's forecast of $45,018,000. I recommend that the Commission remove the $10,857,000 from the Company's forecasted capital expenditures.

For the projected test year, I used 2,369 units multiplied by the Company's forecasted unit cost of $9,571 to arrive at the forecasted capital expenditures of $22,674,000.[10] This

[9] Company forecasted unit cost of $10,814 is on line 38 of the attachment in Exhibit AG-1.
[10] Id. For forecasted unit cost of $9,571.

amount is $9,667,000 lower than the Company's forecast of $32,341,000. I recommend that the Commission remove the $9,667,000 from the Company's forecasted capital expenditures.

Regarding the Make-Ready Relocations, the Company forecasted 7,697 units for the bridge period for a total cost of $45,837,000 at an average unit cost of $5,955. For the projected test year the Company forecasted 6,572 units at a total cost of $39,265,000 at an average unit cost of $5,975. As shown in Figure 15 on page 35 of Ms. Partlan's direct testimony, in the past three years, the number of Make-Ready orders or units completed ranged between 1,236 and 1,640. Therefore, the forecasted periods include a major escalation in number of units projected by the Company.

In discovery, the Attorney General asked the Company to provide the basis for the large escalation in forecasted Make-Ready work for 2025, 2026, and 2027. In response, the Company pointed to page 34 of Ms. Partlan's testimony and a Staff discovery response. Both references provide a general discussion of federal grants for expansion of broadband in rural areas but no specific basis or calculations to show how the Company arrived at the forecasted number of units. In response to discovery, the Company also provided the number of Make Ready orders received in the first 8 months of 2025 in comparison to the same period in 2024. The data show that Make-Ready orders increased 37 percent in the

2025 year to date period over the prior year.[11] This is the only indication available of a recent rate of increase in orders.

Using the 37% rate of increase for the 8-month period, I applied it to the 326 orders the Company received in September through December 2024 (1,640 for 2024 – 1,314 year to date August 2024). I added the resulting 447 orders to the 1,796 orders received year to date August 2025 to arrive at a total forecasted number of units of 2,243 for the full year 2025. I also applied the 37% rate of increase to subsequent years to arrive at forecasted units of 3,073 for 2026 and 4,210 units for 2027. These numbers provided the basis to calculate the number of units of 3,267 for the bridge period and 5,975 for the projected test year.[12]

Based on these revised forecasted units, I determined forecasted capital expenditures of $19,455,000 for the bridge period by multiplying the 3,267 units by the Company's forecasted average unit cost of $5,955. The revised forecasted capital expenditures are $26,382,000 less than the Company's forecast of $45,837,000. I recommend that the Commission remove this difference for the Company's forecasted expenditures for the bridge period.

Similarly, I determined a revised capital expenditures amount of $20,626,000 for the projected test year by multiplying the 3,452 units by the Company's forecasted unit cost

[11] Exhibit AG-3 includes DR AG-CE-0341 with attachment.
[12] BP: 2,243 for 2025 + 3,073 for 2026 x 4/12 = 3,267. PTY: 3,073 x 8/12 + 4,210 x 4/12 = 3,452.

of $5,975. The forecasted capital expenditures are $18,639,000 lower than the Company's forecast of $39,265,000. I recommend that the Commission remove this difference for the Company's forecasted capital expenditures for the projected test year.

Therefore, in total, for LVD Asset Relocations, I recommend that the Commission remove $37,239,000 for the bridge period and $28,305,000 from the Company's forecasted capital expenditures.

3. LVD Lines Reliability

Line 7 of Exhibit A-113 (MPK-3) shows forecasted capital expenditures for LVD Lines Reliability of $180,763,000 for the 16-month bridge period ending April 2026 and $312,886,000 for the projected test year ending April 2027. Figure 35 on page 69 of Ms. Partlan's direct testimony shows that this subprogram consists of nine capital categories with their respective forecasted capital spending and related units for the bridge period and projected test year. In my testimony below, I will address four of these categories: Zonal Health Improvements, Voltage Conversion, Underground Cable Rejuvenation, and Right-of-Way costs.

Zonal Health Improvements – Based on the forecasted capital expenditures and number of units, the Company's forecasts reflect a unit cost of $123,380 ($61,320,000 / 497) for the bridge period and $199,525 ($34,917,000 / 175) for the projected test year. In response to discovery, the Company provided the historical capital expenditures in this category from 2021 to 2024. This information shows that the number of units increased significantly in

2022 and 2023 to 10,509 and 7,749 over the 169 units in 2021, which decreased the unit cost to approximately $3,000. In 2024, the number of units declined to 511.[13] In the discovery response, the Company also revealed that a portion of the work in this category includes the installation of fuses on the lines, which are high volume and lower cost. From the historical data, it appears that most of the fusing work occurred in 2022 and 2023 with significantly fewer installations in 2024, the bridge period, and the projected test year.

In 2024, the most recent historical year of actual expenditures, the Company completed 511 units at a cost of $33,987,994 for a calculated unit cost of $66,513. The number of units completed in 2024 is comparable to the 497 units forecasted by the Company for the bridge period and the 175 units forecasted for the projected test year. However, the unit cost is considerably divergent with the forecasted unit cost of $123,380 for the bridge period being nearly double the historical unit cost for 2024 and the projected test year unit cost of $199,525 being nearly three times the 2024 historical unit cost. The Company has not provided any justification for such a large variance in unit cost from one year to the next or what changed in the projects that increases that cost significantly. The forecasted unit costs for the bridge period and projected test year are excessive, not adequately supported, and need to be tempered to a more reasonable level.

Using the historical unit cost of $66,513 and adjusting it for the inflation factor, I calculated a bridge period unit cost of $68,442.[14] This cost multiplied the Company's

[13] Exhibit AG-4 includes DR AG-CE-0346.
[14] $66,513 x 1.029 = $68,442.

forecasted 497 units results in forecasted capital expenditures of $34,016,000. This amount is $27,304,000 lower than the $61,320,000 forecasted by the Company. I recommend that the Commission remove this difference from the Company's forecasted capital expenditures for the bridge period.

For the projected test year, I applied another year of inflation to the bridge period unit cost to arrive at a forecasted unit cost of $70,085.[15] This cost multiplied by the forecasted units of 175 results in forecasted capital expenditures of $12,265,000. This amount is $22,652,000 lower than the $34,917,000 forecasted by the Company. I recommend that the Commission remove this difference from the Company's forecasted capital expenditures for the projected test year.

Voltage Conversions – The capital spending and number of projects completed in this category has varied from 2021 to 2024, ranging from $90,300 and 3 projects in 2023 to $2.4 million and 5 projects in 2021.[16] For the bridge period, Figure 35 on page 69 of Ms. Partlan's direct testimony, shows that the Company is forecasting 44 projects for a total cost of $8,427,000 for a calculated unit cost of $191,523 and 283 projects for a total cost of $33,115,000 for the projected test year. However, in the attachment provided in response to DR AG-CE-0346, the Company shows that it plans to complete 165 units for each year 2026 and 2027. Based on these latest numbers, the projected test year units are 165, instead of the 283 units shown in Figure 35. The lower number of units for 2026

[15] $68,442 x 1.024 = $70,085.
[16] Exhibit AG-4 includes DR AG-CE-0346.

seems to be more in line with the 44 forecasted units for the bridge period and a more reasonable projection for the ramp-up to the projected test year.

Even based on the more recent lower units, the Company is still ramping up work significantly in this area from less than 10 units annually during the past four historical years to 33 units in 2025 and 165 units in 2026 and 2027.[17] In response to discovery, the Company stated that the increased planned activity is necessary to mitigate safety risk of underground wires, while also increasing operational flexibility and inventory processes. With the increased number of units, the Company also expects to realize economies of scale.[18] The forecasted capital expenditures of $33,115,000 for the projected test year divided by the 165 units results in a unit cost of $200,697. As stated above, the average unit cost for the bridge period is $191,523. When compared to the 2024 unit cost of $136,044, the forecasted costs proposed by the Company do not show the claimed economies of scale.

Using the most recent actual unit cost of $136,044 from 2024 and applying the inflation factor of 2.9%, I calculated a forecasted unit cost of $139,989 for the projected test year. By applying this cost to the 44 units forecasted by the Company, I determined a reasonable capital expenditures forecast of $6,160,000 for the bridge period. This amount is

[17] Id.
[18] Id. DR AG-CE-0346c.

$2,267,000 less than the Company's forecast of $8,427,000. I recommend that the Commission remove this difference from the Company's forecasted capital expenditures.

Although the ramp-up in the number of projects from the bridge period to the projected test year is significant by nearly four-fold, I accept the Company's forecast of 165 units as necessary to resolve safety risks. Using this forecast and applying the inflation adjusted forecasted unit cost of $143,345, I calculated a reasonable capital expenditures forecast of $23,653,000 for the projected test year.[19] This amount is $9,462,000 lower than the Company's forecast of $33,115,000. I recommend that the Commission remove the $9,462,000 from the Company's forecasted capital expenditures for the projected test year.

Underground Cable Rejuvenation – In Figure 35, Ms. Partlan shows forecasted capital spending of $27,909,000 for the bridge period and 68 projects for a calculated average unit cost of $410,426. For the projected test year, the forecasted spending is $65,989,000 for 158 projects for a unit cost of $417,652. In comparison, historical unit costs in the four years 2021 to 2024 ranged from $90,664 to $224,660 with the number of projects ranging from 5 to 10 annually. The average unit cost in the most recent three years was $161,392. The average unit cost for 2024 was $168,852. The Company's forecasted unit costs based on the forecasted spending and planned number of units are excessive, not adequately supported, and need to be moderated.

[19] $139,989 x 1.024 = $143,345 x 165 = $23,653,000.

The three-year average unit cost adjusted for inflation should be representative of the cost of completing future projects, particularly with the significant ramp up in activity in future periods and the expected economies of scale that will likely be achieved. Using the average unit cost of $161,072 and adjusted for inflation, I determined a unit cost of $166,072 for the bridge period, which by multiplying it by the Company' forecasted 68 units results in forecasted capital expenditures of $11,293,000. This amount is $16,616,000 lower than the $27,909,000 forecasted by the Company. I recommend that the Commission remove this difference from the Company's projected bridge period capital expenditures.

For the projected test year, I added another year of inflation to the bridge period unit cost to arrive at a forecasted unit cost of $170,058. By multiplying this cost by the Company's forecasted 158 units, I determined forecasted capital expenditures of $26,869,000 for the projected test year. This amount is $39,120,000 less than the Company's forecast of $65,989,000. I recommend that the Commission remove the $39,120,000 from the Company's forecasted capital expenditures.

Right-of-Way (ROW) Costs – In Figure 35, Ms. Partlan shows ROW costs of $6,188,000 for the bridge period and $17,667,000 for the projected test year. Historical ROW costs ranged from $4.2 million to $6.2 million during the four years from 2021 to 2024.[20] The projected test year increase to more than $17 million represents a significant increase that

[20] Exhibit AG-4 included DR AG-CE-0346 with attachment.

has not been adequately supported by the Company. In response to discovery, the Company stated that there are no individual projects supporting the ROW forecast and the Company used a 14% ratio of historical ROW costs to target capital investments. No data or calculation were provided to support the 14% or the range of 11% to 19% noted in the discovery response.[21]

The 14% ratio used by the Company may not be pertinent to the need for ROW easements. Not all capital projects require new or expanded ROW. For example, pole replacements with $127.5 million of spending or 41% of the total capital expenditures of $312.9 million for the projected test year do not generally require new ROW easements unless they are being moved outside the current right of way. Although I find the bridge period ROW costs in line with recent spending in this area, the Company has not adequately associated the ROW costs to specific projects and justified the increased ROW costs to relevant projects planned for the projected test year.

To establish a reasonable forecasted spending level for the projected test year, I used the highest level of ROW costs in the past four years of $6,202,000, which occurred in 2024. This amount is slightly higher than the $6,188,000 forecasted by the Company for the 16-month bridge period ending April 2026. On a 12-month basis, this forecast is an annual cost of $4,641,000. Therefore, the $6,202,000 I propose represents an increase of nearly 35% over the Company's own annualized forecast for the bridge period.

[21] Id. Included DR ST-CE-0155.

The $6,202,000 forecast for the projected test year is $11,465,000 less than the Company's forecast of $17,667,000. I recommend that the Commission remove this difference from the Company's forecasted capital expenditures.

Q. WHAT ARE THE TOTAL ADJUSTMENTS THAT YOU PROPOSE THE COMMISSION SHOULD MAKE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE LVD LINES RELIABILITY PROGRAM?

A. I recommend that the Commission remove $46,187,000 for the bridge period and $82,699,000 for the projected test year from the Company's forecasted capital expenditures.

4. Resiliency

On line 20 of Exhibit A-113 (MPK-3), the Company shows forecasted capital expenditures for Resiliency of $21,194,000 for the 16-month bridge period ending April 2026 and $35,765,000 for the projected test year ending April 2027. The Company spent $7.8 million on this subprogram in 2024, $1.4 million in 2023, and no amounts in prior years. This is a relatively new subprogram created by the Company.

Figure 48 on page 101 of Ms. Partlan's direct testimony shows the capital expenditures and the related number of units for each of the three components of this sub-program within the larger Reliability program. I will address the two components pertaining to Overhead to Underground and the EGLE-MIEJ Undergrounding Secondary & Services.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL TO ACCELERATE CONVERSION OF OVERHEAD LINES TO UNDERGROUND AND THE RELATED CAPITAL EXPENDITURES.

A. In Figure 48, the Company shows forecasted capital expenditures of $1,250,000 to convert 1.4 miles during the bridge period and $20.0 million to convert 50 miles for the projected test year. Ms. Partlan provides a discussion of Overhead to Underground Conversions beginning on page 98 of her direct testimony. She identifies 7 criteria for selecting overhead lines for undergrounding. These criteria are: LVD system zones that are single-phase; have had at least one outage in the last 24 months; serve between 10 and 200 customers; be operated at one of the three standard wye voltages; not be considered for another reliability project; have a load after installation of 36% or less of the ampacity of the newly installed facilities; and be located in an area that has experienced tree- or weather-related outages. These criteria have been reduced from 9 in the previous rate case U-21585 with the requirement of CAIDI (restoration time) of 600 minutes or more removed and the requirement that the LVD line not supply an overhead system also removed. The Company also modified the location of the overhead line from being located in an area of dense trees to being located in an area that has experienced tree or weather-related outages.[22] The changes indicate that the Company is still struggling to find an

[22] Case No. U-21585, Donald Lynd direct testimony at page 142.

effective approach that adequately justifies undertaking the overhead to underground conversions.

Mr. Kelly also provides a discussion of undergrounding overhead lines beginning on page 60 of his direct testimony. His discussion is mainly on the results of the undergrounding pilot project that was approved by the Commission in Case No. U-21389. In Figure 24 on page 42 of his testimony, Mr. Kelly also provides comparative net present value costs of undergrounding overhead lines versus other options, showing that undergrounding is the most expensive option versus other alternatives. Mr. Kelly also presents a comparison of costs for the four alternatives after imputing societal costs based on the ICE calculator.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSAL TO UNDERTAKE AN EXPANDED CONVERSION OF OVERHEAD LINES TO UNDERGROUND?

A. There are several problems with the Company's proposal. First, the criteria outlined on page 99 of Ms. Partland's direct testimony are relatively low thresholds that could result in hundreds if not thousands of overhead lines that could qualify for conversion to underground. For example, low thresholds such as only one outage in the last 24 months, 10 to 100 customers affected, and lines located in an area that experiences tree or weather-related outages would likely apply widely. It is not clear how these thresholds were determined and why they are relevant. In discovery in Case U-21585, the Attorney General asked the Company to provide the number of projects and miles of overhead lines

that would meet the 9-point criteria (now 7-point) and the related cost to achieve the undergrounding of those lines in future years. In response, the Company stated that it had not determined the number of projects and the miles of overhead lines that would meet all nine criteria.[23] It is hard to understand how the Company can develop relevant criteria without knowing what the impact or outcome would be.

Second, the criteria do not include a cost/benefit analysis (CBA) to determine whether the conversion is economic versus other options for each project. This is a major shortcoming, and the Commission should not approve any undergrounding program that lacks such a key criterion. In response to discovery, the Company had no relevant answer regarding why a CBA was not incorporated in the selection criteria.[24] In this rate case, the Attorney General asked again if the Company will include a present value economic analysis to determine that each undergrounding project is the least cost option. The response states that the Company does not plan to include this key screening criterion.

Third, the results of the pilot program show a calculated average cost of $443,079 per comparable mile of overhead line converted to underground. However, 5 of the 8 projects in the pilot program, or 63%, had a cost that was above the average cost from 20% to 126% of the average cost. Even excluding the Saugatuck-Douglas project at 126% above the average cost, which the Company claims was unusual and would not repeat, the next highest cost project was $693,773 per mile, or 74% above the average cost of $443,079.

[23] U-21585 Exhibit AG-1.9 includes DR AG-CE-0492.
[24] Id.

The pilot confirms the point that each project can vary significantly from the average cost per mile and needs to pass an economic cost/benefit analysis to qualify as an acceptable candidate for undergrounding versus other alternatives.

Fourth, the information in Figure 24 on page 62 of Mr. Kelly's testimony is revealing, showing that even at the average cost per mile undergrounding is not a sound economic practice. The presentation in Figure 25 with the societal benefits from assumed avoided customer outages should be disregarded. The ICE calculator information used in the analysis assumes that for each minute of sustained power interruptions customers incur an equal cost. In reality, this is not the case. Some customers can sustain power outages for hours without incurring costs. It is when power outages span into a day or longer that potentially costs are incurred. Therefore, the ICE calculator tends to overestimate the cost of short outages outside of major storms, which are more common. The most pertinent comparison is the cost incurred by the Company for each alternative, as shown in Figure 24, which all customers must pay. On this basis, undergrounding is more costly on average in comparison to other alternatives presented by the Company.

Q. DID THE COMMISSION RECENTLY PROVIDE PERTINENT DIRECTION TO THE COMPANY AS TO HOW TO PROCEED WITH CONVERSIONS OF OVERHEAD LINES TO UNDERGROUNDING?

A. Yes. In its June 12, 2025 order in Case No. U-21305, the Commission evaluated the skepticism voiced in the Final Liberty Consulting Group report about the Company

pursuing overhead to underground projects. The Liberty Report stated that the Company should delay expansion of LVD undergrounding beyond the pilot program and pointed out that costs and reliability of benefits of undergrounding remain uncertain to support expansion of the program. The Commission also considered comments on the Liberty Report from various parties, including the Attorney General.

The Commission agreed with the comments from the Attorney General and MNSC, stating that it remains skeptical of the costs of the undergrounding pilot at scale but was not opposed to further consideration of the program. Specifically, the Commission requested additional evidence, including a cost/benefit analysis, to fully evaluate the proposed undergrounding in comparison to other alternatives.[25]

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The Company's proposal to undertake an expanded conversion of overhead lines to underground has not been well defined, it lacks important criteria to ensure that sound economic decisions are made, it is based on a misleading average cost per mile of overhead line to be converted to underground and should be rejected.

I recommend that the Commission remove the incremental capital spending of $1,250,000 proposed by the Company for the bridge period and the $20 million for the projected test year.

[25] Case No. U-21305, June 12, 2025 order for Consumers Energy at page 25.

Q. WHAT IS YOUR ASSESSMENT OF THE EGLE-MIEJ UNDERGROUNDING SECONDARY AND SERVICES PROJECTS?

A. The Company included forecasted capital expenditures for three EGLE-MIEJ Undergrounding projects in Grand Rapids, Flint, and Kalamazoo for the bridge period totaling $4,118,000 and the same amount for the projected test year. Figure 48 on page 101 of Ms. Partlan's testimony shows these amounts and they are included in Exhibit A-130. In discovery, the Attorney General asked the Company to provide the current phase of project development for the three projects. In response, the Company reported that they are in the scoping phase.[26] The projects are still in the preliminary phase of development. No design or other advanced work has been performed on the projects. Therefore, the costs and timing of the projects are still preliminary and are premature for inclusion in rate base in this rate case.

I recommend that the Commission remove the capital expenditures of $4,118,000 from both the bridge period and projected test year.

Q. WHAT IS THE TOTAL AMOUNT OF ADJUSTMENTS THAT YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE RESILIENCY SUBPROGRAM?

[26] Exhibit AG-6 included DR AG-CE-0363 with attachments.

A. I recommend that the Commission remove $5,368,000 for the bridge period and $24,118,000 for the projected test year from the Company's forecasted capital expenditures.

5. LVD Line Capacity

On line 22 of Exhibit A-113 (MPK-3), the Company shows forecasted capital expenditures for LVD Line Capacity of $28,580,000 for the 16-month bridge period ending April 2026 and $54,911,000 for the projected test year ending April 2027. Figure 54 on page 116 of Ms. Partlan's direct testimony shows the capital expenditures and the related number of units for the two component categories in this sub-program: the Overload Equipment Upgrades and the Lines Capacity Projects for Substation Work.

Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES FORECASTED BY THE COMPANY FOR THE OVERLOADED EQUIPMENT UPGRADES?

A. In Figure 52 on page 111 of her direct testimony, Ms. Partlan shows the number of circuits and components categorized by percentage of overload from Minor Risk to High Risk. Figure 53 on page 115 of Ms. Partlan's testimony shows the dramatic increase in spending in this subprogram from less than $10 million annually in the past five years to nearly $30 million in the bridge period and $55 million in the projected test year. In discovery the Attorney General asked the Company to explain whether the ramp-up in spending is directed at the high-risk circuits with over 140% overload. In response the Company stated

that the spending will occur across the board for all overload percentages during the bridge period and the projected test year.[27]

The Company believes that different types of devices face different severity of risk at different percentages of overload level. This reasoning does not match with the Company's own categorization of risk or severity shown in Figure 52. It is only logical that if certain circuits have been categorized as High-Risk that those circuits incorporate the severity of the related equipment within the circuit. Otherwise, the categorization is meaningless.

In discovery, the Attorney General also asked the Company to identify the number of circuits to be addressed in the bridge period and projected test year by risk level and the related capital spending on each. The response shows that for the bridge period the Company plans to work on 83 projects that fall in the over 140% overload category with related spending of $15,989,000. The Company also reported that 41 projects with related capital spending of $5,375,000 pertain to circuits that have an overload condition of less than 140%. For the projected test year, the Company is targeting 85 circuits with overload conditions of 140% or more and related capital expenditures of $11,527,000. The Company is also targeting 155 circuits that are in the less risky categories for total forecasted capital spending of $40,911,000. What is even more perplexing is that 111 of the 155 circuits have overload conditions of 119% or less.

[27] Exhibit AG-7 includes DR AG-CE-0357 with attachment.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE COMPANY'S FORECASTED SPENDING PLAN ON LVD LINE CAPACITY SUBPROGRAM?

A. The Company's spending priorities for the LVD Line Capacity subprogram are inconsistent with its categorization of risk. The dramatic increase in spending is not focused on the higher risk circuits and is not adequately supported. I recommend that the Commission remove $5,375,000 of capital expenditures for the bridge period and $40,911,000 for the projected test year that is directed at the lower risk projects with overload of less than 140%.

6. LVD Transformers

On line 5 of Exhibit A-113 (MPK-3), the Company shows forecasted capital expenditures for LVD Transformers of $227,963,000 for the 16-month bridge period ending April 2026 and $207,782,000 for the projected test year ending April 2027. Figure 64 on page 137 of Ms. Partlan's direct testimony shows the significant increase in spending in the forecasted periods over the prior five years. According to Ms. Partlan's testimony, the increase in spending is driven by both volume and price increases. The volume increases are from new purchases of pad mount transformers tied to increase undergrounding work for new services, primary and secondary circuits likely related to undergrounding overhead lines, and EVs. Although Figure 65 on page 138 of Ms. Partlan's direct testimony shows the number of units for each year, in response to discovery the Company stated that the

numbers for 2026 and 2027 are incorrect. The Company provided the correct units with the discovery response.[28]

The information provided by the Company in response to discovery shows that the forecasted capital expenditures for the bridge period and projected test year include large increases in 1-phase and 3-phase pad mount transformers from 2024 to 2027. The forecast for the 1-phase pad mount transformers shows an increase from 2,876 units in 2024 to 7,469 units in 2027. This total increase over the three-year period reflects an increase of 63% in 2025 over 2024 and 34% in 2026. These increases are on top of a 48% increase in the number of units in 2023 over 2022 and another 24% increase in 2024 over 2023.

The forecast for the 3-phase pad mount transformers shows similar high increase of 64% in 2025 over 2024 followed by a decrease of 20% in 2026 and an increase of 60% in 2027. The increase in units from 2023 to 2024 was 32%. The increases for 2025 through 2027 are excessive and are not supported by any calculations or sound basis other than general statements about projects that may need new pad mount transformers. As shown in Figure 4 on page 11 of Ms. Partlan's testimony, New Service Connections are forecasted to increase at an annual rate of approximately 1% from 2024 to the projected test year. The number of miles of undergrounding projects is 1.4 miles in the bridge period and 50 miles in the projected test year. This level of activity does not justify the forecasted increases in

[28] Exhibit AG-8 includes DR AG-CE-0361 with attachments.

pad mount transformers. Furthermore, I recommended that the Commission reject the Company's proposed undergrounding projects.

Q. DID YOU CALCULATE AN APPROPRIATE NUMBER OF 1-PHASE AND 3-PHASE PAD MOUNT TRANSFORMERS FOR THE BRIDGE PERIOD AND PROJECTED TEST YEAR?

A. Yes. To provide the Company with some additional inventory of 1-phase pad mount transformers for the bridge period and projected test year, I used the 24% rate of increase in 2024 actual purchases over the number in 2023. This rate of increase applied to the 2,876 units purchased in 2024 results in 5,040 units for the bridge period and 4,776 units for the projected test year.[29]

For the bridge period, I multiplied the 5,040 units by the year-to-date price of $5,287 per unit provided by the Company that already reflect inflation based on actual prices billed by vendors.[30] The result is forecasted capital expenditures of $26,646,000. This amount is $9,791,000 less than the cost of $36,437,000 included in the Company's forecasted capital expenditures for the bridge period. Exhibit AG-9 shows how I determined the Company's forecasted cost. I recommend that the Commission remove the $9,791,000 from the Company's forecasted capital expenditures.

[29] 2024 units of 2,876 x 1.24 = 3,566 units for 2025 x 1.24 = 4,422 for 2026 x 1.24 = 5,483 units for 2027. BP: 3,566 for 2025 + 4,422 units for 2026 x 4/12 = 5,040. PTY: 4,422 x 8/12 + 5,483 x 4/12 = 4,776 units.
[30] Exhibit AG-8 includes DR AG-CE-0361 with attachments.

For the projected test year, I adjusted the bridge period price for the 1-phase pad mount transformer by inflation to arrive at a price of $5,414.[31] This price multiplied by the forecasted units of 4,776 results in forecasted capital expenditures of $25,857,000. This amount is $11,777,000 lower than the Company's forecasted cost of $37,634,000.[32] I recommend that the Commission remove the $11,777,000 from the Company's forecasted capital expenditures.

Q. PLEASE EXPLAIN HOW YOU FORECASTED THE 3-PHASE PAD MOUNT TRANSFORMERS AND RELATED CAPITAL EXPENDITURES FOR THE BRIDGE PERIOD AND PROJECTED TEST YEAR.

A. For 3-phase pad mount transformers for the bridge period and projected test year, I used the 32% rate of increase in 2024 actual purchases over the number in 2023. This rate of increase applied to the 564 units purchased in 2024 results in 991 units for the bridge period and 820 units for the projected test year.[33]

For the bridge period, I multiplied the 991 units by the year-to-date price of $27,217 per unit based on the information provided by the Company that already reflects inflation in actual prices billed by vendors.[34] The result is forecasted capital expenditures of $26,972,000. This amount is $5,514,000 less than the cost of $32,486,000 included in the

[31] $5,287 x 1.024 = $5,414.
[32] Exhibit AG-9.
[33] 2024 units of 564 x 1.32 = 744 units for 2025. 2026 units kept at 741 per Company forecast. 2027: 741 units for 2026 x 1.32 = 978. BP: 744 for 2025 + 741 units for 2026 x 4/12 = 991. PTY: 741 x 8/12 + 978 x 4/12 = 820 units.
[34] Exhibit AG-8 includes DR AG-CE-0361 with attachments.

Company's forecasted capital expenditures for the bridge period. Exhibit AG-9 shows how I determined the Company's forecasted cost. I recommend that the Commission remove the $5,514,000 from the Company's forecasted capital expenditures.

For the projected test year, I adjusted the bridge period price for the 3-phase pad mount transformer by inflation to arrive at a price of $27,870.[35] This price multiplied by the forecasted units of 820 results in forecasted capital expenditures of $22,853,000. This amount is $3,005,000 lower than the Company's forecasted cost of $25,858,000.[36] I recommend that the Commission remove the $3,005,000 from the Company's forecasted capital expenditures.

Q. WHAT IS THE TOTAL ADJUSTMENT TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES THAT YOU RECOMMEND FOR THE BRIDGE PERIOD AND THE PROJECTED TEST YEAR FOR LVD TRANSFORMERS?

A. I recommend that the Commission remove $15,305,000 for the bridge period and $14,782,000 for the projected test year from the Company's forecasted capital expenditures for LVD Transformers.

7. LVD Repetitive Outages

On line 12 of Exhibit A-113 (MPK-3), the Company shows forecasted capital expenditures for LVD Repetitive Outages of $21,089,000 for the bridge period and $30,344,000 for the

[35] $27,217 x 1.024 - $27,870.
[36] Exhibit AG-9.

projected test year. Figure 39 on page 79 of Ms. Partlan's direct testimony shows that capital spending on this subprogram has been erratic from year to year ranging from $4.1 million in 2023 to $10.7 million in 2021. The most two recent years 2023 and 2024 have been extremely meager with annual spending of $4.1 million and $4.5 million for a program of significant importance that is enshrined in the Commission's standards of performance. This spending pattern is confusing given that repetitive outages have been an area of concern for the Commission and other parties participating in prior proceedings, including the Attorney General.

In discovery, the Attorney General asked the Company to explain why the capital spending on this subprogram varied significantly from year to year. In response, the Company pointed back to pages 80 and 81 of Ms. Partlan's direct testimony for the explanation.[37] The referenced testimony discusses work performed in other areas, such as LVD Lines Reliability and LVR Resiliency that the Company believes accomplish the same goal of reducing SAIDI and CEMI. If it is true that work accomplishes the same outcome, it is not clear why the Company is now forecasting capital spending in the bridge period and projected test year in the Repetitive Outages program that is four times to six times higher than the amount spent in 2024.

The forecasted capital expenditures of $21,090,000 for the bridge period are for 246 units or projects. This translates to a unit cost of $85,728. For the projected test year, the

[37] Exhibit AG-10 included DR AG-CE-0349.

forecasted capital expenditures are $30,344,000 for 337 projects at an average unit cost of $90,042. Line 35 in the attachment in Exhibit AG-1 shows this information plus the historical spending, number of units and average cost per unit. The average number of projects completed in the most recent historical three years is 228 at an average cost of $27,032. The average cost per unit in 2024 was $20,890. Therefore, the Company's forecasted average unit costs of $85,728 for the bridge period and $90,042 for the projected test year are extremely inflated and not representative of recent actual costs. The Company has not provided any specific justification for the large difference in the forecasted unit costs versus recent historical costs.

Although I accept the Company's forecasted number of projects for the bridge period and projected test year as a reasonable progression toward more activity and focus on this problem area, the average unit costs are excessive and need to be moderated down to the recent actual costs experienced. Using the three-year historical average unit cost of $27,032 from 2022 to 2024, I adjusted this cost by the inflation rate of 2.9% to arrive at a bridge period unit cost of $27,816. I multiplied this cost by the 246 units forecasted by the Company to arrive at forecasted capital expenditures of $6,843,000. This amount is $14.246,000 lower than the $21,089,000 forecasted by the Company. I recommend that the Commission remove this difference from the Company's forecasted capital expenditures for the bridge period.

For the projected test year, I adjusted the bridge period unit cost by the inflation rate of 2.4% to arrive at a unit cost of $28,484, which applied to the 337 units forecasted by the

Company resulted in forecasted capital expenditures of $9,599,000. This amount is $20,745,000 lower than the capital expenditures of $30,344,000 forecasted by the Company. I recommend that the Commission remove the $20,745,000 from the Company's forecasted capital expenditure for the projected test year.

Q. ARE THERE OTHER CONCERNS WITH THE COMPANY'S PLANNED PROJECTS TO ADDRESS REPETITIVE OUTAGES THAT YOU WANT TO DISCUSS?

A. Yes. In discovery, the Attorney General asked the Company to identify the outage minutes experience by customer in 2023 and 2024 on the same circuits that the Company plans to address in the bridge period and projected test year for repetitive outages. The information provided by the Company shows that for several projects, and nearly half of the total projects, customers had not experienced any interruption minutes in 2023 and 2024. This is odd because if the Company is targeting circuits with repetitive outages there should be outage minutes in at least one if not both of those two years. Additionally, the Company identifies customer outage minutes avoided that in total exceed the total number of outage minutes experienced by customers in 2023 or 2024.

This contradictory information raises concerns about the accuracy of the purported reduction in outage minutes and whether the Company is targeting the appropriate circuits that experience multiple power outages year after year. I recommend that the Commission direct the Company to provide more pertinent information that shows the worst circuits

with repetitive outages are being targeted and that the avoided customer interruption minutes reflect actual reductions from historical outage minutes experienced by customers on that circuit.

8. LVD Substations Rehabilitation

On line 16 of Exhibit A-113 (MPK-3), the Company shows forecasted capital expenditures for LVD Substations Rehabilitation of $40,895,000 for the bridge period and $31,147,000 for the projected test year. Figure 42 on page 96 of Ms. Hayward's direct testimony shows the capital spending for each of the two components of this subprogram with related number of units. I will address each of the two categories separately.

The first item pertains to the replacement of Allis Chalmers substation transformers. On page 91 and 92 of her direct testimony, Ms. Hayward discusses some of the inherent problems that the transformers have, which the Company had dealt with for decades. Ms. Hayward states that 37 of these transformers are still in operation as of early 2025 and the Company's plans appear to be to replace all 37 and perhaps others by the end of the projected test year. Figure 42 shows the Company's plans to replace 26 in the bridge period and 18 units in the projected test year for a total of 44 units.

The table on page 92 of Ms. Hayward's direct testimony shows that the pace of replacement declined in the most recent historical three years from prior years. The DR attachment in Exhibit AG-1 on line 60 shows that on average between 2022 and 2024, the Company replaced 4 units annually. Therefore, the 26 units planned to be replaced in the

bridge period and the additional 18 units in the projected test year represent a significant increase in activity. It is apparent that the Company now wants to accelerate the replacement rate to make up for fewer replacements in the past three years. The acceleration is excessive and burdensome to customers that ultimately must pay the cost of replacement. My recommendation is that the Company stretch replacement over a longer number of years past 2026.

Therefore, I propose that the number of units to be replaced in the bridge period be set at 9 units which is more than twice the average number of units replaced in the past three years. For the projected test year, the number of forecasted units should be set at 8, which is twice the historical average number. The remaining 14 units should be replaced over the subsequent two years.

Using the 9 units forecasted for replacement in the bridge period, I applied the Company's forecasted unit cost of $864,038 to arrive at forecasted capital expenditures of $7,776,000. This amount is $14,689,000 lower than the Company's forecasted capital expenditures of $22,465,000. Similarly, the projected test year, I used the 8 units multiplied by the Company's forecasted cost of $808,222 to arrive at capital expenditure of $6,466,000. This amount is $8,082,000 less than the Company's forecasted capital expenditures of $14,548,000.

I recommend that the Commission remove the $14,699,000 and $8,082,000 from the Company's forecasted capital expenditures for the bridge period and projected test year, respectively.

Q. WHAT ADJUSTMENTS DO YOU PROPOSE FOR EQUIPMENT REPLACEMENT AND REGULATORY?

A. Similar to the Allis Chalmers' transformers, the Company forecasted significant escalations in the number of projects to be completed during the bridge period and the projected test year for the Equipment Replacement and Regulatory category. For the bridge period, the Company forecasted 26 units for a total cost of $18,430,000 and average unit cost of $708,846. For the projected test year, the company forecasted total capital expenditures of $16,599,000 for 13 projects at an average cost of $1,276,846.[38]

During the most recent historical three years, the Company had about 10 projects annually at an average unit cost of $511,340. The Company did not provide any explanation, evidence, or justification for the higher forecasted unit cost for the bridge period and projected test year. I find the three-year average unit cost adjusted for future inflation as a reasonable basis to forecast capital expenditure for the bridge period and projected test year.

[38] Megan Hayward direct testimony at 96, Figure 42.

For the bridge period, I used 13 projects multiplied by $526,000 to arrive at forecasted capital expenditure of $6,838,000.[39] This amount is $11,592,000 lower than the $18,430,000 forecasted by the Company. For the projected test year, I multiplied the adjusted unit cost of $539,000 to 10 forecasted units to arrive at forecasted capital expenditures of $5,390,000.[40] This amount is $11,209,000 less than the Company's forecasted amount of $1,599,000. Therefore, I recommend that the Commission remove $11,592,000 and $11,209,000 from the Company's forecasted capital expenditures for the bridge period and projected test year,

Q. WHAT IS THE TOTAL AMOUNT OF ADJUSTMENTS THAT YOU PROPOSE FOR THE LVD SUBSTATIONS REHABILITATION PROGRAM?

A. I recommend that the Commission remove $26,291,000 from the bridge period and $19,291,000 for the projected test year from the Company's forecasted capital expenditures.

9. LVD Substations Capacity

On line 24 of Exhibit A-113 (MPK-3), the Company shows forecasted capital expenditures for LVD Substations Capacity of $29,656,000 for the bridge period and $22,251,000 for the projected test year. Figure 56 on page 133 of Ms. Hayward's direct testimony shows

[39] $511,340 x 1.029 = $526,000 rounded down.
[40] $526,000 x 1.024 = $539,000 rounded up.

the capital spending for each of the two components of this subprogram with related number of units. I will address each of the two categories separately.

Regarding New Substations, the company forecasted four new stations for the bridge period at a total cost of $5,136,000. This forecast is in line with historical trends, and I will not propose any adjustments. However, for the projected test year, the Company forecasted 11 new units at a total cost of $20,301,000 and an average unit cost of $1,845,727. In the past four years, the Company has completed between 3 and 8 new stations with no stations built in 2023.[41] Excluding 2023 but including 2021 instead, for the most recent three years, the Company completed an average of 5 new stations annually. The Company has not provided sufficient evidence why the historical average number needs to double for the projected test year and why 11 new stations need to be built.

In keeping with the historical level of activity, I forecast 5 units for the projected test year at the Company's forecasted unit cost of $1,845,727. This results in capital expenditures of $9,229,000. This amount is $11,074,000 lower than the company's forecast of $20,303,000. I recommend that the Commission remove this difference from the Company's capital expenditures for the projected test year.

Regarding the Existing Substations, the Company forecasted 19 substations for capacity expansion for the bridge period at a cost of $24,520,000. For the projected test year, the Company forecasted 4 expansion projects at a cost of $1,948,000. In the most recent three

[41] Exhibit AG-1 includes DR AG-CE-0364 with attachment.

years 2022-2024, the Company completed from 7 to 12 projects a year with an average number of 9 units annually. The bridge period forecast more than doubles the average annual number of units. The Company has not provided evidence that a doubling of this activity is necessary.

In discovery, the Attorney General asked the Company to identify the problems that are being addressed by the units forecasted for the bridge period. In response, the Company referenced back to the direct testimony of Ms. Hayward and provided a list of stations indicating station overload conditions. Ms. Hayward's testimony provides only general statements about addressing customers increasing load demands with no specifics. Similarly, the list attached to the discovery response does not identify the level of overload experienced and why these are priority projects that need to be completed in the bridge period.[42]

Based on the recent historical level of activity, I forecast 12 units (9 x 16/12) for the 16-month bridge period at the average cost per unit of $656,000 adjusted for inflation or $675,000 per unit. This results in forecasted capital expenditures of $8,100,000.[43] This amount is $16,420,000 less than the Company's forecasted capital expenditures of $24,520,000.

[42] Exhibit AG-11 includes DR AG-CE-0477.
[43] Average unit cost for 2022-2024: $656,000 x 1.029 = $675,000 x 12 = $8,100,000.

Therefore, in total, for the LVD Substations Capacity subprogram, I recommend that the commission remove $16,420,000 for the bridge period and $11,074,000 for the projected test year from the Company's forecasted capital expenditures.

10. HVD Lines Reliability

On line 8 of Exhibit A-113 (MPK-3), the Company shows forecasted capital expenditures for HVD Lines Reliability of $133,667,000 for the bridge period and $107,667,000 for the projected test year. Figure 21 on page 49 of Ms. Hayward's direct testimony shows the capital spending for each of the seven components of this subprogram with related number of units. I will address three of the categories: Line Rebuilds, Pole Top Rehabilitation, and Pole Replacements.

Before discussing the individual components of this subprogram and other HVD subprograms that will follow, it is worth pointing out that the Company's HVD system is in much better shape than the LVD system. On page 7 of her direct testimony, Ms. Hayward shows that the SAIDI reliability index, excluding major event days (MED) has been trending down over the past 10 years. This is a strong indication that power outages caused by the HVD system have decreased over the 10-year period as a result of a short vegetation clearing cycle and a base level of capital improvements. Therefore, large increases in capital spending should not be needed across the board on this system and the focus on any increase in capital spending should be directed to the LVD system. With that background in mind, I have taken a critical review of the Company's large increase in

spending on some of the HVD subprograms, particularly where insufficient justification is provided to support the increase in spending.

Line Rebuilds – In Figure 21, the Company forecasted 13 miles of line rebuilds for the bridge period at a total cost of $38,614,000 and an average unit cost of $2,201,000. For the projected test year, the Company forecasted 65.8 miles of line rebuilds for a total cost of $35,743,000 for an average unit cost of $543,207.

Line rebuilds in the most recent historical three years have averaged 20 miles annually with the highest year in 2022 at 40 miles.[44] I find the number of miles forecasted for the bridge period reasonable, albeit at a high unit cost. However, the nearly 60 miles of rebuilds for the projected test year is a 50% increase from the highest rebuild year in the last three years and three-fold increase over the average number of miles rebuilt in recent years. The increase is excessive and not supported by sufficient data, showing that the higher level of activity is required for the projected test year.

To determine a reasonable level of activity, I used the highest level of line rebuild activity in the past three years of 40 miles. Using this number of units and multiplying it by the Company's forecasted unit cost of $53,207, I forecast capital expenditures for the projected test year of $21,778,000. This amount is $14,015,000 lower than the Company's

[44] Exhibit AG-3 DR AG-CE-0364 attachment, line 15.

forecast of $35,743,000. I recommend that the commission remove this difference from the Company's forecasted capital expenditures for the projected test year.

Pole Top Rehabilitations – In Figure 21, the Company forecasted 54.7 miles of pole top rehabilitations for the bridge period at a total cost of $9,097,000 and an average unit cost of $166,307. For the projected test year, the Company forecasted 116.1 miles of pole top rehabilitations for a total cost of $11,996,000 for an average unit cost of $103,325.

Pole top rehabilitations in the most recent historical three years have averaged 50.5 miles annually with wide disparity from year to year.[45] I find the 54.7 miles forecasted for the bridge period in line with the historical average and reasonable. However, the 116 miles of rebuilds for the projected test year is an increase of 130% over the average number of miles rebuilt in recent years. The increase is excessive and not justified by any details, showing that the higher level of activity is required for the projected test year.

Based on the 50 miles of pole top rehabilitations completed on average in the past three years, I applied the company's forecasted unit cost of $103,325 to arrive at forecasted capital expenditures of $5,166,000 for the projected test year. This amount is $6,830,000 less than the Company's forecasted capital expenditures of $11,996,000. I recommend that the Commission remove this $6,830,000 from the Company forecasted capital expenditures for the projected test year.

[45] Exhibit AG-3 DR AG-CE-0364 attachment, line 16.

Pole Replacements – In Figure 21, the Company forecasted 2,010 poles for replacement for the bridge period at a total cost of $54,856,000 and an average unit cost of $27,292. For the projected test year, the Company forecasted 1,161 poles for replacement for a total cost of $33,569,000 for an average unit cost of $28,914.

Pole replacement in the most recent historical three years have averaged 442 annually. On pages 43 to 45 of her direct testimony, Ms. Hayward discusses the pole replacement program and points out that the Company built a backlog of "red tagged" poles that need to be replaced, which the Company has neglected to replace in prior years. The increased activity in pole replacements in the bridge period and projected test year reflects the Company's objective to accelerate pole replacements and significantly reduce the backlog over a three-year period.

In discovery, the Attorney General asked the Company to explain why it allowed a backlog of pole replacements to build and did not address the replacement of those poles timely in prior years. The response is not clear and mentions leveraging an undisclosed tactic and another tactic of combining replacement with pole top rehabilitations and rebuilds. It also mentions that the Company's previous tactics and methodology involved time-consuming efforts to obtain right-of-way permissions and work permits. In response to discovery, the Company also provided the build-up in the backlog from 2016 to 2027. This additional

information shows that the backlog predated the year 2016 with 1,353 to be replaced, which steadily increased the backlog to 2,250 poles by the end of 2024.[46]

From this information, it is apparent that the Company has been remiss in addressing the backlog timely and now wants to accelerate the replacement over the three years from 2025 to 2027. This acceleration places a large cost burden on customers over the bridge period and projected test year. To lessen that burden, I propose that the increase in pole replacements to reduce the backlog be spread over five years. The Company forecasted that it plans to replace 3,790 poles over the three years 2025-2027. This includes replacing 2,490 newly tagged poles for replacement over the same time period. The difference of 1,300 is the number of additional poles that the Company plans to replace over the three-year period to reduce the backlog, which is 433 additional pole replacements annually.[47] If the 1,300 pole replacements are spread over five years, the annual additional pole replacements would be 260 or 173 fewer than the Company has proposed.[48]

The 173 fewer pole replacements translate to 231 fewer poles for the bridge period, which at a unit cost of $27,292 result in capital expenditure reductions of $6,304,000. For the projected test year, the 173 fewer pole replacements at the unit cost of $28,914 result in lower capital expenditures of $5,002,000. I recommend that the Commission remove the

[46] Exhibit AG-12 includes DR AG-CE-0465.
[47] 1,300 / 3 = 433.
[48] 1,300 / 5 = 260 – 433 = 173.

$6,304,000 for the bridge period and the $5,002,000 for the projected test year from the Company's forecasted capital expenditures.

Q. WHAT ARE THE TOTAL ADJUSTMENTS THAT YOU RECOMMEND TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR HVD LINES RELIABILITY?

A. I recommend that the Commission remove $6,304,000 for the bridge period and $25,847,000 for the projected test year from the Company's forecasted capital expenditures.

11. HVD Substation Reliability

On line 10 of Exhibit A-113 (MPK-3), the Company shows forecasted capital expenditures for HVD Substation Reliability of $47,322,000 for the 16-month bridge period ending April 2026 and $39,680,000 for the projected test year ending April 2027. Figure 29 on page 64 of Ms. Hayward's direct testimony shows the capital expenditures and the related number of units for the four spending categories within this sub-program. I will address the spending level for Circuit Breakers and Other.

Circuit Breakers - In Figure 29, the Company forecasted 63 circuit breaker/switcher replacements for the bridge period at a total cost of $20,038,000 for an average unit cost of $27,292. For the projected test year, the Company forecasted 1,161 poles for replacement for a total cost of $33,569,000 for an average unit cost of $318,063. For the

projected test year, the Company forecasted the replacement of 74 circuit breakers/switchers for a total cost of $23,737,000 and for a unit cost of $320,770.

In the most recent historical three years, circuit breaker/switcher replacements averaged 17 annually at an average unit cost of $133,500.[49] Ms. Hayward's direct testimony provides no specific explanation or justification for why the number of replacement units should increase from an average annual replacement rate of 17 to 67 in the bridge period and 74 for the projected test year. No specific anomalies or problems have been identified with the targeted replacements to justify this four-fold increase in replacement activity. Also, no explanation or justification was provided why the replacement unit cost for the bridge period and projected test year more than doubles from $133,500 in the most recent three years to more than $300,000 in the next two years.

To develop a reasonable forecast of capital expenditures for the bridge period and taking into consideration some amount of increased activity, I doubled the historical level of replacements to 40 and applied the inflation-adjusted historical average unit cost of $137,372.[50] The calculation results in forecasted capital expenditures of $5,495,000. This amount is $14,543,000 lower than the Company's forecast of $20,038,000. I recommend that the Commission remove the $14,543,000 from the Company's forecasted capital expenditures for the bridge period.

[49] Exhibit AG-1, DR AG-CE-0364 attachment line 28.
[50] $133,500 x 1.029 = $137,372.

Similarly, for the projected test year, I used the same 40 replacement units multiplied by the inflation adjusted average unit cost of $140,669 to arrive at capital expenditures of $5,627,000. This amount is $18,130,000 lower than the Company's forecast of $23,737,00. I recommend that the Commission remove this difference from the Company's forecasted capital expenditures for the projected test year.

Other/Miscellaneous - In Figure 29, the Company forecasted 169 units for the bridge period for a total cost of $22,277,000 for undefined Other Projects. For the projected test year, the Company forecasted 83 units for a total cost of $12,758,000. In the most recent historical three years, capital spending in this category ranged from $332,000 to $1.1 million.[51] Ms. Hayward's direct testimony is devoid of any explanation for this dramatic increase in spending. In response to discovery, the Company points to Exhibits A-109 and A-110 for what is included in Other Projects.[52] The exhibits list several animal mitigation projects and DSCDA projects, but they do not provide any explanation or justification for why these projects are escalating significantly over historical periods.

To set a reasonable amount of capital spending in this area and taking into consideration some amount of increased activity, I doubled the highest amount spent by the /Company in the prior three years from $1.1 million to $2.2 million for both the bridge period and projected test year. The $2.2 million results in a reduction of $20,277,000 from the Company's forecasted capital expenditures for the bridge period. Similarly, for the

[51] Exhibit AG-1, DR AG-CE-0364 attachment line 31.
[52] Exhibit AG-13 includes DR AG-CE-0469.

projected test year, the $2.2 million results in a reduction of $10,558,000 from the Company's forecasted amount of $12,758,000. I recommend that the Commission remove those differences from the Company's forecast capital expenditures.

Q. WHAT IS THE TOTAL ADJUSTMENT THAT YOU RECOMMEND FROM THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR HVD SUBSTATION RELIABILITY?

A. I recommend that the Commission remove $34,820,000 for the bridge period and $30,888,000 for the projected test year from the Company's forecasted capital expenditures for HVD Substation Reliability.

12. HVD Premature Projects

In discovery, the Attorney General asked the Company to provide a list of HVD projects of $3.0 million or greater included in the bridge period and the projected test year, specifying the current phase of development of the project. The request also asked the Company to identify the next phase of project development with start and completion dates along with the cost of the project and other pertinent information.

The information provided by the Company shows that 5 projects in the bridge period have been cancelled, have not yet started the design phase, are still in the early stage of project design, or have a placeholder amount without a known specific project. The total forecasted capital expenditures included by the Company in the bridge period for these

projects is $34,654,000. The projects have been highlighted and identified on pages 2 and 3 of Exhibit AG-14.

The cancelled projects, totaling to $27,305,000, should be removed along with the placeholder amount of $7,349,000 for unknown "High Probability" projects under the Strategic Customers New Business. The Commission has repeatedly ruled that placeholder amounts should not be included in rate base. These remaining projects are still in the early phase of development, and it is uncertain if and when they will be completed and at what specific cost. Therefore, it is premature to include the capital expenditures for these projects in rate base. Customers should not pay in rates for the return on investment, depreciation expense, and other costs related to projects that may not go into service and not be used and useful before the end of the projected period. If the Company completes the projects, the costs related to those projects can be recovered in a subsequent rate case.

Therefore. I recommend that the Commission remove the total amount of $34,654,000 from the Company's forecasted capital expenditures for the bridge period.

Similarly, for the projected test year, there are 13 projects that have been cancelled, do not have specific projects associated with forecasted dollars, are currently in the scoping phase, or no design and engineering work has yet been completed. The total capital expenditures for the 13 projects in the projected test year are $78,051,000. Those projects have been highlighted and identified on pages 4 to 9 of Exhibit AG-14.

Of the 13 projects, one project with forecasted capital expenditures of $20,619,000 was cancelled. The Company has also included capital expenditures of $6,470,000 under New Business Strategic Customers for high probability projects that have not yet been identified. This is a placeholder amount and should be removed. The remaining projects are still in the early phase of development, and it is uncertain if and when they will be completed and at what specific cost. Therefore, it is premature to include the capital expenditures for these projects in rate base.

For the same reasons discussed above, the capital expenditures related to these 13 projects should not be included in rate base. Therefore, I recommend that the Commission remove the $78,051,000 from the Company's forecasted capital expenditures for the projected test year.

Q. ARE THERE CERTAIN CONCERNS YOU WANT TO RAISE REGARDING PROJECTS UNDERTAKEN BY THE COMPANY FOR LARGE STRATEGIC CUSTOMERS?

A. Yes. As discussed above, the Company recently had two large projects cancelled for two large strategic customers. One cancellation occurred after the Company had already incurred $11.6 million in capital expenditures on the project and for the second one it is not yet clear whether the project was cancelled before or after the Company incurred any costs related to the project.[53] These events raise three major concerns. First, the Company

[53] Exhibit AG-15 includes DR AG-CE-0479.

is following a strategy of purchasing equipment and will likely begin design work on certain projects before the customer has signed a contract to expedite completion of the project. This is a very risky undertaking that the Company may want to undertake on its own but should not be done on the shoulders of customers.[54]

Second, even after the project is completed and the customer begins operations there is still a high degree of risk that the customer may cease operations or decide to move to another state. This poses the risk of stranded assets that the Company will likely want to continue to recover from the rest of its customer base. These large strategic customer projects typically involve single customer dedicated substations, power lines, and related facilities at costs exceeding tens of millions of dollars. Although some of the equipment can be salvaged and reused on other future projects, the remaining costs, plus the cost of teardown and transportation can still be large. Often the Company does not obtain a contribution in aid of construction (CIAC) under its economic development tariff (LEDR). Although the contract may provide for some make-whole payments, those provisions may prove worthless if the customer goes out of business.

In discovery, the Attorney General asked the Company what provisions have been included in the contract with large customers for reimbursement of capital expenditures and O&M expenses incurred by the Company in case the customer abandons the project before completion of construction and also subsequent to start of operations but before the

[54] Id. Includes DR AG-CE-0480b.

Company has recovered the full investment in the project. In response, the Company stated that contracts with customers depending on the type of contract have minimum billing requirements for certain energy usages and terms, and/or provisions for prorated payment of investments if the customer ceases operation prior to the end of the term of the contract. Additionally, the Company performs risk reviews on projects over $1 million and may require additional security, such as a letter of credit or parental guaranty).[55] Based on the Company's response, only two appear of the projects appear to have any provisions for a letter of credit or parental guaranty. Therefore, the risk that customers could potentially face large stranded costs still remains.

Third, regarding the accounting of costs incurred on cancelled projects, the response to DR AG-CE-0479 stated that the Company billed the former customer for a portion of the costs incurred for the cancelled project and retained the remainder in work in process pending resolution of salvage activities. This accounting treatment is not appropriate. Once a project has been cancelled, the costs should be removed from rate base and accounted separately below the line. If some of the facilities, equipment, or materials is later reused on utility projects than those amounts should be charged to future projects costs and rate base at that time.

Q. WHAT IS YOUR RECOMMENDATION?

[55] Id. Includes DR AG-CE-0478c.

A. I recommend that the Commission direct the Company to take appropriate steps to protect customers from future stranded costs pertaining to large customer facilities installations, including obtaining bank letters of credit and parental guaranties at the time a contract is signed to avoid future disputes or reacting to unexpected events. Additionally, I recommend that the Commission direct the Company to adopt an accounting policy to remove costs from rate base for cancelled projects.

13. Grid Modernization

On line14 of Exhibit A-113 (MPK-3), the Company shows forecasted capital expenditures for Grid Modernization of $25,691,000 for the bridge period and $17,837,000 for the projected test year. This subprogram consists of various spending categories, as detailed in Figure 1 on page 12 of Mr. Scott McPhail's direct testimony. I will focus my discussion on certain components within Distribution Circuit Modernization and Distribution Asset Management.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSED CAPITAL SPENDING WITHIN DISTRIBUTION CIRCUIT MODERNIZATION?

A. In Figure 1, Mr. McPhail shows forecasted capital spending for Line Sensors, Voltage Regulator Controllers, Peer to Peer Automation and Metro Modernization. I will address each of these spending categories individually.

Line Sensors - The Company forecasted $6,116,000 of capital expenditures for the bridge period with no related units. Figure 5 provides historical spending levels with the related number of units. In response to discovery, the Company reported that it forecasted 1,000 units for the bridge period.[56] Based on the forecasted capital expenditures of $6,116,000, the average unit cost for the 1,000 Sensor units is $6,116. This unit cost is considerable higher than $3,636 unit cost incurred by the Company in 2024 and the three-year average of $2,549. Mr. Phail did not provide any explanation or justification for the large increase in the unit cost for the bridge period.

Given the upward trend in the unit cost in recent years, I used the most recent actual unit cost of $3,637 for 2024 adjusted for inflation to calculate a reasonable capital expenditures forecast for the bridge period. After adjusting for inflation, the average unit cost is $3,741.[57] This cost multiplied by 1,000 units results in forecasted capital expenditures of $3,741,000. This amount is $2,345,000 lower than the $6,116,000 forecasted by the Company. I recommend that the Commission remove this difference from the Company's forecasted bridge period capital spending.

Voltage Regulator Controllers - The Company forecasted $10,526,000 of capital expenditures for the bridge period but no related units. In response to discovery, the Company reported that it forecasted 294 units for the bridge period. Based on the forecasted capital expenditures, the average unit cost for the 294 units is $35,803. This

[56] Exhibit AG-16 includes DR AG-CE-0541.
[57] $3,636 x 1.029 = $3,741.

unit cost is considerable higher than the $22,442 unit cost incurred by the Company in 2024 and the three-year average of $19,357. For the projected test year, the Company forecasted capital expenditures of $5,120,000 and in response to discovery identified that it forecasted 143 units for the year for a calculated unit cost of $35,804, which is the same as the bridge period. Mr. Phail did not provide any explanation or justification for the large increase in the unit cost for the bridge period or the projected test year.

Given the upward trend in the unit cost in recent years, I used the most recent actual unit cost of $22,442 for 2024 adjusted for inflation to calculate a reasonable capital expenditures forecast for the bridge period. After adjusting for inflation, the average unit cost is $23,093.[58] This cost multiplied by 294 units results in forecasted capital expenditures of $6,789,000. This amount is $3,737,000 lower than the $10,526,000 forecasted by the Company. I recommend that the Commission remove this difference from the Company's forecasted bridge period capital spending.

Similarly, for the projected test year, I multiplied the inflation-adjusted unit cost of $23,647 by the 143 units forecasted by the Company to arrive at forecasted capital expenditures of $2,382,000.[59] This amount is $1,738,000 less than the Company's forecast of $5,120,00. I recommend that the Commission remove the $1,738,000 from the Company's forecasted test year capital expenditures.

[58] $22,442 x 1.029 = $23,093.
[59] $23,093 x 1.024 = $23,647.

Peer to Peer Automation and Metro Modernization - The Company forecasted capital expenditures for the bridge period of $895,000 for Peer-to-Peer Automation and $305,000 for Metro Automation. For the projected test year, the respective forecasted capital expenditures are $270,000 and $650,000. Although on pages 33-42 of her testimony, Ms. Hayward describes some of the features of the two technology systems and estimates potential avoided customer interruption minutes, there is no evidence that these technologies have worked effectively at other utilities and provided proven benefits. They appear to be more experimental than tried and tested. In response to discovery, the Company stated that it had not performed a cost/benefit analysis to demonstrate there is some economic value to this new technology.[60]

Due to the lack of a convincing and compelling case that the two proposed technology systems will create significant value for customers, I recommend that the Commission disallow the combined capital expenditures of $1,200,000 for the bridge period and $920,000 for the projected test year.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSED CAPITAL SPENDING ON THE DISTRIBUTION ASSET MANAGEMENT?

A. Mr. McPhail discusses the Electric Distribution Asset Management systems beginning on page 49 of his testimony. In Figure 9 on page 51, he shows capital expenditures for the projects that total to $1,740,000 for the bridge period and $4,050,000 for the projected test

[60] Exhibit AG-16 includes DR AG-CE-0541c.

year. In his testimony, Mr. McPhail mentions that the implementation costs of the Asset Repository system have increased and for the Asset Performance Management system, the Company found that purchasing and installing a new system would be prohibitively expensive and decided to build its own system in-house.

In discovery, the Attorney General asked the Company to provide both the original estimated cost and the current forecasted cost of the systems along with other pertinent information. In response, the Company reported that the original estimated cost of the Asset Repository system was approximately $2.5 million, including development O&M costs. The Company now forecasts the revised cost of the system will be $8.8 million, including O&M costs.[61] This is a huge increase in a relatively short timeframe. The Company proposed this system in the two prior rate cases, dating back to 2023.

In response to discovery, the Company explained that the initial capital estimate was based on early planning assumptions and as the project progressed it proved to be more complex and costly. The Company also stated that the software-as-a-service model tool was higher than originally forecasted. This is a classic case of not doing enough upfront research and analysis, making a decision to proceed with a project based on sketchy information, and finding out later that the cost mushroomed to five times more than originally estimated.

In the last rate case, I questioned the need to undertake this project and the related Asset Performance Management system and recommended that the Commission disallow the

[61] Exhibit AG-17 includes DR AG-CE-0544 with attachments.

forecasted capital spending. My conclusion in Case U-21585 was that the Company had not made a compelling case that the new systems were necessary and that current systems could no longer be used. The Company had not performed a cost/benefit analysis (CBA) in the last case but provided one in this case, incorporating all the systems it wants to implement, including the Asset Repository, Asset Performance Management system, Asset Investment Planning system, and the Device Management system. This last system is a new system that the Company added in this rate case at a cost of $2.5 million without any explanation or justification.

The CBA is based on the original total cost of all systems of approximately $16 million instead of the current forecast of nearly $21 million. Therefore, it is stale. With the new higher cost the net present value is no longer favorable and it is now at about breakeven, assuming all of the soft savings included in the CBA are achievable. The purported savings were not documents and it is not possible to determine whether they are realistic or achievable. The Company also included cost savings attributed to "Societal Improved Power Quality" and reduced "Reliability Degradation Risk." These are vague concepts that are not likely to provide tangible and realistic cost savings to the Company or its customers. In other words, the Commission should not rely on any representations from the Company that the proposed systems are economically justified.

Customers should not pay for projects that are incurring significant cost overruns and are not economically justified. Additionally, the Asset Performance Management system is

still in the planning phase of development, and it is premature to include its capital spending in rate base in this rate case.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE DISTRIBUTION ASSET MANAGEMENT SYSTEMS?

A. I recommend that the Commission remove the forecasted capital expenditures of $1,740,000 for the bridge period and $4,050,000 for the projected test year from this rate case.

Q. WHAT IS THE TOTAL CAPITAL EXPENDITURES DISALLOWANCE THAT YOU PROPOSE FOR THE GRID MODERNIZATION SUBPROGRAM?

A. For the total Grid Modernization subprogram, I recommend that the Commission remove $9,022,000 for the bridge period and $6,708,000 for the projected test year.

B. Power Generation - Capital Expenditures

As shown on page 1 of Exhibit A-12 (RTB-3), Schedule B-5.2, the Company incurred capital expenditures of $145.3 million for Power Generation plant in 2024, and forecasted $275.4 million for the bridge period, and $188.6 million for the projected test year. Included in these total amounts are capital expenditures for Steam (Fossil Fuel) Power Generation, Hydro Power Plants, Pumped Storage Generation (Ludington), and Other Production Plant. In my testimony below, I will evaluate and propose adjustments to some of these programs and component projects.

1. Covert Power Plant

Q. HAVE YOU IDENTIFIED CERTAIN ADJUSTMENTS TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR THE COVERT POWER PLANT?

A. Yes. On page 2, line 43, of Exhibit A-12 (RTB-3), Schedule B-5.2, the Company shows capital expenditures for the Covert power generation plant of $67.5 million for the bridge period and $61.4 million for the projected test year. On pages 62 through 74 of his direct testimony, Mr. Richard Blumenstock discusses several capital projects to update and upgrade various equipment and systems in the plant.

The Company purchased this natural gas-fueled plant and began operating it in June 2023. In discovery, the Attorney General asked the Company to explain why it was replacing and upgrading large pieces of equipment and systems so soon after the Company had purchased the plant and to disclose whether it was aware of the poor conditions of the equipment at issue during the acquisition due diligence process. In response, the Company stated that it anticipated making future capital investments but was not able to conduct robust health assessments and detailed engineering evaluations until after taking ownership of the plant.[62] It appears that the Company bought the plant without realizing that it required considerably larger capital expenditures to replace old and failing equipment and systems much sooner than expected. It is apparent that the Company failed

[62] Exhibit AG-18 includes DR AG-CE-0490.

to perform sufficiently robust technical due diligence that could have uncovered these deficiencies and resulted in a lower purchase price. For customers to pay now for the capital upgrades and replacement, they would be paying twice for the same equipment and systems with the Company having already paid a higher purchase price for the plant than justified. In addition, the Company plans to recover the new investment through depreciation expense and will effectively receive a return on twice the investment in the same equipment and systems.

Q. ARE THERE SPECIFIC CAPITAL EXPENDITURES THAT YOU PROPOSE SHOULD NOT BE INCLUDED IN RATE BASE IN THIS RATE CASE DUE TO THE SHORT COMINGS OF THE DUE DILIGENCE PROCESS?

A. Yes. I have two items. First, on page 62 and 65 of his direct testimony, Mr. Blumenstock discusses the replacement of the Load Commutated Inverter (LCI) Static Frequency Converters (SFC) at a cost of $1,305,000 in the bridge period and $2,610,000 in the projected test year. The LCI-SFC is a piece of equipment and system used with the gas turbines and related equipment at the plant. Mr. Blumenstock states in his testimony that replacement of the SFC is required to mitigate the significant risk of failure due to obsolescence, ensure operational reliability, and align with manufacturer recommendations. If this is such a critical component that must be replaced two years after purchasing the plant, it begs the question why the Company did not discover the problem during its technical due diligence.

Second, on pages 62 and 66 of his testimony, Mr. Blumenstock discusses the extensive upgrading of the Netmation Operating System to the latest version at a cost $2,922,000 in the bridge period and $8,844,000 in the projected test year. Mr. Blumenstock states on page 66 that the Covert plant, operational since 2004, faces critical challenges with outdated control systems. The Netmation upgrade includes replacement of input/output models, servers, network switches and software. The same question must be asked here. If this is such a critical system that must be replaced two years after purchasing the plant, it begs the question why the Company did not discover the problem during its technical due diligence. At the time of purchase, the Company should have considered the implication of purchasing a power plant that would have to be overhauled shortly after it was acquired.

Furthermore, as shown in Exhibit AG-21, the Netmation project is still in the early stage of design and engineering development, which is scheduled to be completed in February 2026. This project has not advanced sufficiently to be included in rate base in this rate case. The cost and timing of the project may still change significantly until the engineering work is completed.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. Customers should not pay for the cost of a recently purchased power plant and shortly thereafter pay for significant upgrades that should have been discovered in the technical due diligence and deducted from the purchase price. I recommend that the Commission

disallows the total bridge period capital expenditures of $4,227,000 and remove the $11,454,000 for the projected test year for the two systems discussed above from inclusion in rate base.

2. Ludington Power Plant

Q. HAVE YOU IDENTIFIED CERTAIN ADJUSTMENTS TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR THE LUDINGTON POWER PLANT?

A. Yes. On page 3, line 57, of Exhibit A-12 (RTB-3), Schedule B-5.2, the Company shows capital expenditures for the Ludington power generation plant of $15,225,000 for the bridge period and $13,282,000 for the projected test year. On pages 91 through 97 of his direct testimony, Mr. Richard Blumenstock discusses several capital projects to update and upgrade various equipment and systems in the plant. The plant went through extensive equipment and system overhauls to each of its 6 units between 2015 and 2022.

In discovery, the Attorney General asked the Company to explain why such large capital spending on equipment and system upgrades was necessary so soon after the major overhaul of the 6 units that occurred as recent as three years ago. In response, the Company stated that the proposed capital expenditures in this rate case address components that were outside the scope of the original overhaul. The Company provided no evidence to support

this statement.[63] It is questionable why large systems and equipment components, such as the Units 1 through 6 DCS Control Relay at a cost of nearly $3 million would not have been replaced at the time of the units' major overhaul. The same question applies also to the Lower Penstock Expansion Joint Chamber Waterstop, Hydro Governor Replacement, Pony Motor Overhaul, etc. (pages 91-97, Blumenstock testimony).

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The Company has not provided sufficient evidence to justify that the capital upgrades it seeks to recover in this rate case as necessary at this time given the recent overhaul of the plant. Therefore, I recommend that the Commission the forecasted bridge period capital expenditures of $15,225,000 and also remove the $13,282,000 for the projected test year from the Company's forecasted capital expenditures for the Ludington power plant.

3. Campbell Power Plant

Q. HAVE THERE BEEN RECENT DEVELOPMENTS REGARDING THE PLANNED RETIREMENT OF THE CAMPBELL POWER PLANT SCHEDULED FOR MAY 2025?

A. Yes. On May 23, 2025, the Department of Energy (DOE) issued an order that the Campbell power plant continue to operate past May 2025 and directed FERC and MISO to issue appropriate directives to the Company to effect the continued operation of the

[63] Exhibit AG-19 include DR AG-CE-0493.

plant and related cost recovery and tariffs. Prior to the DOE May 2025 order the Company was proceeding with recovery of remaining plant costs subsequent to retirement of the plant based on the approval received in Case No. U-21090 and prepared the current case on that basis.

In light of the DOE order and FERC August order in Docket No. EL2-90-000, the Attorney General asked the Company to explain how it planned to handle any changes to the cost recovery included in this rate case. In response, the Company stated that it would not propose any changes to the rate case filing with regard to the Campbell plant continued operation and stated that it plans to refund any amounts collected through the FERC process to its MPSC customers to the extent that such amounts may have been collected through MPSC jurisdictional rates.[64]

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY POSITION ON THE RATE CASE IMPACT AND FUTURE REFUNDS TO BE MADE TO CUSTOMERS?

A. Although the ideal solution would have been to unwind the settlement in Case No. U-21090 given sufficient time and a clearer view of the length of the continued operation of the Campbell plant. That solution would not work at this time. Therefore, the Company proposed solution to make later refunds is the only workable solution at this time.

[64] Exhibit AG-20 includes DR AG-CE-0683.

However, to ensure that a full and proper accounting of costs and revenue from the continued operation of the Campbell plant occurs, as well as the cost recovery in rates established in Case U-21585 and in the current case, I recommend that the Commission open a new docket for a contested proceeding to review all aspects, impacts, cost and revenue reconciliation, and refunding of net amounts to customers.

Q. ARE THERE OTHER MATTERS THAT RELATE TO THE CAMPBELL PLANT THAT YOU WISH TO BRING TO THE ATTENTION OF THE COMMISSION?

A. Yes. In the current rate case, the Company proposed to undertake a Waste Water Treatment System at the Campbell plant and relocation of the machine shop at the plant in anticipation of the plant closure. The capital expenditures are $17,782,000 for the bridge period and $9,600,000 for the projected test year. These amounts are included on line 64 of page 3 of Exhibit A-12, Schedule B5.2 under Administration and Other and discussed on pages 98-99 of Mr. Blumenstock's direct testimony.

Furthermore, in response to discovery, the Company reported that the Waste Water Treatment System is still in the planning phase of development and it does not appear it has not advanced sufficiently to be included in rate base in this rate case. No design or engineering work has been completed, and the cost and timing of the project may change significantly. Exhibit AG-21 provides additional information.

In light of the continued operation of the Campbell plan, the uncertainty surrounding the length and manner of its operation under FERC jurisdiction, and the still preliminary phase

of development of the project, I recommend that these costs be removed from the Company's forecasted capital expenditures for the bridge period and projected test year in the amount of $17,782,000 and $9,600,000, respectively.

4. Other Premature Power Generation Capital Projects

Q. PLEASE DISCUSS THE CAPITAL PROJECTS WITHIN POWER GENERATION THAT ARE STILL IN THE EARLY STAGE OF DEVELOPMENT AND SHOULD BE REMOVED FROM RATE BASE.

A. In discovery, the Attorney General asked the Company to identify the current phase of development for projects of $3 million or greater. In response, the Company reported that five projects are in the planning phase or recently entered the design/engineering phase.[65] Two of those projects, CGS-Netmation (MHPSA Operating System) and JHC Wastewater Treatment System, have already been addressed and their removal from capital expenditures recommended in my testimony above. The other three projects are:

1. PP-00542: Covert Spare GSU $5,910,000
2. B-PP-00171: (13497) ZGS - Phase II GT Advanced gas path replacement and axial fuel staging $8,331,000
3. PP-00488: ZGS SITE SPARE GSU $4,481,000

These projects were included by the Company in the forecasted capital expenditures for the projected test year in Exhibit A-12 (RTB-3), Schedule B5.2, page 9, for a total amount

[65] Exhibit AG-21 includes DR AG-CE-0496 with attachment.

of $18,722,000. The projects are still in the early stage of development and not sufficiently certain they will proceed at the forecasted cost and timeline. Therefore, I recommend that the Commission remove the $18,722,000 from the Company's forecasted capital expenditures for the projected test year.

C. Operations Support - Capital Expenditures

On line 1 of Exhibit A-12 (QAG-1), Schedule B-5.6, the Company shows forecasted capital expenditures of $23.7 million for the bridge period and $27.4 million for the projected test year for Asset Preservation under Facilities and Shared Services. Page 1 of Exhibit A-102 provides a detailed breakdown of the major projects for the historical year and the forecasted periods. These costs are sponsored by Company witness Quentin Guinn. Included in the forecasted capital expenditures for the bridge period and the projected test year are capital expenditures for the Control/Dispatch Centers in Grand Rapids and Parnal/Jackson and Emergent Repairs. In my testimony below, I will address each of those projects.

With Operations Support, I also address the Company's Fleet Services, which are also sponsored by Mr. Guinn. Exhibit A-12, Schedule B-5.6, page 4, shows the forecasted capital expenditures of $25.9 million for the bridge period and $67.9 million for the projected test year.

1. Control Dispatch Centers

On lines 25 and 26 of page 1 of Exhibit A-102 (QAG-3), the Company shows historical and forecasted capital expenditures for the two Control/Dispatch Centers in Grand Rapids and Parnal Rd-Jackson. The Company spent a combined amount of $2,406,000 in 2024 and forecasted capital expenditures for the two centers of $10,746,000 for the bridge period and $15,497,000 for the projected test year. Although Mr. Guinn sponsors the capital expenditures, the reasons for the projects are addressed by Company witness Andrew Snider beginning on page 37 of his direct testimony.

In his testimony, Mr. Snider discusses the Company's decision to have two fully-staffed control/dispatch centers, one in Grand Rapids and the other in Jackson, Michigan, as the best solution for a fully functional back-up control center in Grand Rapids in addition to the main control center in Jackson. This is a 180 degree turn by the Company in less than 24 months. Just a year ago, the Company advocated for the consolidation of the two centers in Jackson with the Grand Rapids location being an unstaffed backup center. The Company has or had a third dispatch center in Saginaw that was also part of the planned consolidation plan. Company witness Brenda Houtz discussed this initial consolidation plan beginning on page 25 of her direct testimony in Case No. U-21389. Mr. Snider confirmed that plan in his direct testimony in Case No. U-21585, just last year.

The original plan was going to cost $17.2 million in capital spending and create annual cost savings of $8.6 million. The Company's new proposal will cost $30.2 million and

create purported annual cost savings of $10.2 million. The tradeoffs here are not advantageous to customers with the cost of the new proposal increasing by $13 million and the cost savings increasing by only $1.6 million annually.

In his testimony, Mr. Snider dwells on the benefits and cost savings created by the two fully-staffed centers. However, the purported $10.2 million cost savings are not actual cost savings, but potentially avoided additional costs based on anticipated increases in efficiencies and faster customer restoration time of power outages during storms.[66] In response to discovery, the Company provided a list of the cost savings and the underlying assumptions. For example, this information shows that the Company would save $3.1 million in costs by 2027 by accelerating storm restoration by 2 hours per event between 2025 and 2027. The Company does not explain, how two centers will do this instead of one center. In two other examples, the Company would save a combined $3.5 million by announcing an early storm declaration and reducing the ICS storm team activation for smaller storms. Why two fully staffed centers instead of one will create incremental savings is not clear. Exhibit AG-22 includes the Company discovery response with the list of savings. Based on this information, the Company would realize cost savings of $7.8 million in the projected test year.[67]

[66] Exhibit AG-22 includes DR AG-CE-0633.
[67] 2026: $6.6 million x 8/12 = $4.4 million + 2027: $10.2 million x 4/12 = $3.4 million = $7.8 million.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL TO HAVE TWO FULLY STAFFED CONTROL/DISPATCH CENTERS?

A. As discussed above, the Company has not made a compelling and convincing case that having two fully staffed control/dispatch centers is advantageous and in the best interest of customers. The Company is increasing capital expenditures by building two redundant centers and not achieving actual cost savings. Therefore, I recommend that the Commission reject the proposal and remove the forecasted capital expenditures of $10,746,000 for the bridge period and $15,497,000 for the projected test year. However, if the Commission decides to approve the proposal and the related capital expenditures, I recommend that the forecasted cost savings of $7.8 million be included as a reduction to the Company's forecasted O&M expense for the projected test year.

2. Emergent Repairs

On lines 8 of page 1 of Exhibit A-102 (QAG-3), the Company shows forecasted capital expenditures for Emergent Repairs of $1,344,000 for the bridge period and $2,706,000 for the projected test year. No further details were provided by the Company in direct testimony. In discovery, the Attorney General asked the Company to identify any specific and known projects that made up those total amounts. In response, the Company provided a list of projects for the bridge period and stated that there are no known projects for the

projected test year.[68] In effect, the $2,706,000 amount in the projected test year is a placeholder amount. The Commission previously has rejected the inclusion of placeholder amounts in rate base.

Therefore, I recommend that the Commission remove the $2,706,000 from the Company's forecasted capital expenditures.

3. Transportation Fleet

Exhibit A-12, Schedule B-5.6, page 4, shows the forecasted capital expenditures for the Transportation Fleet of $25.9 million for the bridge period and $67.9 million for the projected test year. In comparison, the Company had capital expenditures of $16.6 million in 2024. Mr. Guinn discusses the transportation fleet replacement strategy and other aspects of the composition of the Company's transportation fleet beginning on page 39 of his direct testimony. In Exhibit A-104, Mr. Guinn lists the number of vehicles and field equipment within each vehicle class that the Company purchased in 2024 and plans to purchase in 2025, 2026, and the projected test year along with the related cost.

Included in Exhibit A-104, on line 3, are the additional number of vehicles and equipment that the Company forecasted it will need for the projected test year to support the planned capital spending in the Distribution area. The assumption here is that the Commission will fully adopt the Company's spending plans for future years. To assess the reasonableness of the fleet acquisition plans for the bridge period and projected test year, the Attorney

[68] Exhibit AG-23 includes DR AG-CE-0647.

General asked the Company to provide additional historical information by vehicle class and additional details about the fleet expansion by Distribution program.

In response, the Company provided the requested information for the historical years and the detailed information for the fleet expansion by Distribution program. Generally, I found the forecasted capital spending on new vehicles for the bridge period reasonable, and I will not propose any adjustments. Regarding the projected test year, the fleet expansion detail shows that of the 229 new planned vehicle purchases, 71 vehicles are for electric undergrounding work and 158 vehicles for other LVD programs.[69] In line with my testimony above rejecting the Company's overhead to undergrounding program, I removed from my fleet analysis the 71 vehicles pertaining to this program. Also, due to the significant reductions in LVD capital programs and projects that I have proposed in this rate case, I reduced the number of proposed fleet purchases for LVD projects by half. Taking a conservative approach here protects customers from having excessive vehicles on hand for work that may not materialize. Furthermore, as discussed later in my testimony, the Company has a significant number of vehicles that are not being fully utilized and should focus on better utilization of the fleet to reduce purchases of new vehicles.

[69] Exhibit AG-24 includes DR AG-CE-0661 with attachment.

Q. DID YOU PERFORM A FULL ANALYSIS OF THE FLEET PURCHASES, INCLUDING UNIT COST ADJUSTMENTS AND THE REDUCTIONS TO THE FLEET EXPANSION PLANS FOR THE PROJECTED TEST YEAR?

A. Yes. In Exhibit AG-25, I calculated the average cost per vehicle purchased within each vehicle class during the most recent three years from 2022 and 2024. To arrive at a reasonable unit cost forecast for the projected test year, I applied the inflation factor of 2.9% and 2.4% to reflect the cumulative inflation increase to the end of the projected test year. I then multiplied the inflation-adjusted unit costs by the number of routine vehicles in each class forecasted by the Company. The routine vehicle purchases total to 89 vehicles, and I adopted the same forecast proposed by the Company. The total forecasted purchase cost for those 89 vehicles based on my calculations is $16,407,000. This amount is $4,371,000 lower than the $20,778,000 forecasted by the Company. The difference reflects higher prices for vehicle purchases forecasted by the Company above normal inflation projections. The Company did not disclose any vehicle price data for the projected test year. Therefore, it is not clear where the 2026 and 2027 prices would have been sourced from and their validity.

Regarding the expanded fleet purchases, Exhibit AG-25 reflects the reductions discussed above, removing the undergrounding work-related vehicle purchases and the other reductions to LVD program purchases. To arrive at a reasonable forecast the cost of those vehicle purchases, I applied the same inflation-adjusted unit cost from the average three-year period discussed above for routine purchases. The result is a total forecasted cost of

$18,139,000. This amount is $27,931,000 lower than the Company's forecast of $46,070,000. This difference reflects the lower number of vehicles I included in the forecast and lower unit costs than in the Company's forecast.

In total, the total reduction for the two categories of vehicle purchases is $33,142,000. I recommend that the Commission remove this amount from the Company's forecasted capital expenditures for the projected test year.

Q. SHOULD THE COMMISSION BE CONCERNED WITH THE COMPANY'S LOW UTILIZATION OF A SIGNIFICANT PORTION OF THE COMPANY'S TRANSPORTATION FLEET?

A. Yes. In discovery, the Attorney General asked the Company to provide a list of vehicles and equipment that were utilized less than 50% during 2024 and the date when the vehicle was last used. In response the Company provided a list of 2,278 vehicles and field equipment that met the request. My analysis shows that 381 vehicles were used less than 5% in 2024 with some of these vehicles being last use in June 2021. Approximately 1,050 vehicles were used between 5% and 20%, and the remaining 1,216 vehicles were used only between 20% and 50%.[70]

This information raises concerns with a large portion of the fleet not being sufficient utilized and sitting idle. The Company needs to take steps to improve the utilization rate

[70] Exhibit AG-26 includes DR AG-CE-0656 with the attachment,

of the fleet and minimize new vehicle purchases when existing vehicles are still available for use by field personnel. I recommend that the Commission direct the Company to present a thorough plan in the next rate case that addresses the utilization rate of vehicles and field equipment and the impact on reduced vehicle purchases in future years.

D. Information Technology Projects - Capital Expenditures

In Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, the Company shows forecasted capital expenditures for Information Technology (IT) of $80.3 million for the bridge period and $77.7 million for the projected test year. Within the number of IT projects that Company witness Stacey Baker discusses in her direct testimony, there are several projects that are still the initial phase of development that I determined to be too premature to include in rate base in this rate case, including the large SAP 4/S HANA ERP project. Additionally, I found that the forecasted capital expenditures for ARP-Field Devices are excessive and need to be adjusted downward. In my testimony below, I will discuss the specific capital expenditures disallowances along with any O&M expense adjustments that pertain to each project.

1. Premature IT Projects

Group 1 - Regarding the following four projects, Ms. Baker provides a summary of the capital expenditures of each project and related O&M expense for the projected test year and references the testimony of other Company witnesses for further discussion and project justification.

1. Electric Geographic Information System (GIS) Design Platform Modernization
2. Electric GIS Utility Network Transformation
3. Integrated Energy Management Platform Optimization
4. Service Restoration Artificial Intelligence

In discovery, the Attorney General asked the Company to provide additional cost data, specific project justification, and the phase of project development. In response, the Company provided the forecasted capital expenditures by year and disclosed that the four projects are still in the Investment Planning phase and no detailed requirements have yet been completed.[71] These projects are still in the initial stage of development and significant uncertainty remains whether or when they will advance further. The projects are too premature to include in rate base in this rate case. Customers should not pay for the depreciation and return on project cost that may not materialize within the forecasted time frame.

Based on the cost data provided by the Company, I calculated forecasted capital expenditures for the four projects of $1,448,000 for the bridge period and $3,067,000 for the projected test year. In addition, the Company identified $1,260,000 of O&M expense for the projected test year in conjunction with development of the projects. Exhibit AG-28 provides additional cost details by project. I recommend that the Commission remove these amounts from the Company forecasted capital expenditures and O&M expense.

[71] Exhibit AG-27 include DR AG-0592 with attachments.

Group 2 - Regarding the following five projects, Ms. Baker provides a discussion of each project and the summary capital expenditures with the related O&M expense in her testimony at the pages referenced below next to each project.

1. Critical Substation Upgrade (Baker at 79-80)
2. Data & Analytics Platform Rationalization (Baker at 97-99)
3. OT Datacenter Migration (Baker at 100)
4. Forward Web Proxy Services (Baker at 114-115)
5. Physical Access Management and Alarm Response (Baker at 115-117)

In discovery, the Attorney General asked the Company to provide additional cost data, specific project justification, and the phase of project development. In response, the Company provided forecasted capital expenditures by year and disclosed that the five projects are still in the Investment Planning phase and no detailed requirements have yet been completed.[72] These projects are still in the initial stage of development and significant uncertainty remains whether or when they will advance further. The projects are premature to include in rate base in this rate case. Customers should not pay for the depreciation and return on project cost that may not materialize within the forecasted time frame.

Based on the cost data provided by the Company, I calculated forecasted capital expenditures for the five projects of $6,283,000 for the bridge period and $11,428,000 for the projected test year. In addition, the Company identified $1,876,000 of O&M expense

[72] Exhibit AG-29 include DR AG-0594, 0595, 0596, 0601, and 0602 with attachments.

for the projected test year in conjunction with development of the projects. Exhibit AG-28 provides additional cost details by project. I recommend that the Commission remove these amounts from the Company forecasted capital expenditures and O&M expense.

In total, for the 9 projects, I recommend that the Commission remove $7,731,000 for the bridge period and $14,495,000 for the projected test year from the Company's forecasted capital expenditures. In addition, I recommend that the Commission remove $3,136,000 from the projected test year O&M expense.

2. SAP S/4 HANA Project

Q. PLEASE BRIEFLY DISCUSS THE NEW SAP-ERP SYSTEM DEVELOPMENT PROJECT PROPOSED BY THE COMPANY AND THE RELATED CAPITAL EXPENDITURES.

A. Beginning on page 102 of her direct testimony, Ms. Baker discusses the implementation of a new Enterprise Resource Planning (ERP) system with SAP Software Company (SAP). The Company also refers to this system as the SAP S4/HANA development project. My testimony here mirrors the testimony I recently filed in the Company's gas rate case in Case No. U-21806 on this same topic. The capital expenditures have been updated to reflect the portion applicable to the electric business. In response to discovery, the Company confirmed that prior information provided in Case No. U-21806 is still valid. The Company also confirmed that the project is still in the Investment Planning phase and no detailed requirements for the new system have been completed.

The Company identified the total cost of the project at [Begin Conf] [redacted] [End Conf].

In her direct testimony, Ms. Baker states that the current ERP system with SAP needs to be modernized because it will reach the end of mainstream vendor maintenance on December 31, 2027. Although the system would be modernized with a new software system, it will basically replace the same functions of the current ERP system of billing, materials purchasing, warehousing, finance, accounting, payroll, customer relationship management, and other technical functions.[74] In response to discovery, the Company stated that the current SAP-ERP system functions well and it is being replaced because of the end of system support by SAP.[75] This is clearly a case of forced obsolescence by the vendor in order to sell new software, services, and technology.

[73] U-21870 Stacey Baker direct testimony at 102 and Exhibit AG-30 CONF includes DR AG-CE-0598 with ATT_1 CONF.
[74] U-21806 Exhibit AG-28 CONF. includes DR AG-CE-0622 with ATT_1 CONF and AG-CE-0850 CONF.
[75] U-21806 Exhibit AG-29 includes DR AG-CE-0624.

On page 106 of her direct testimony, Ms. Baker states that the Company will extend the current system support and maintenance service with SAP past the December 2027 date and into 2028, noting that the extended support is only available until 2030. In discovery, the Attorney General asked the Company whether it had asked SAP to extend the service and support agreement through and potentially past 2030. In response, the Company stated that it had not done so and pointed out that it would need to purchase extended support,[76] which in a subsequent discovery response the Company identified at [Begin Conf] [redacted] [End Conf].[77] This fee for system support is logical and is likely similar to what the Company currently pays for system support and software releases and upgrades. Operating the current system past 2030 is a viable solution given that the system is still functioning well and is meeting all the operating requirements of the Company.

Furthermore, the Company has not identified any cost savings or financial benefits for implementation of a new ERP system. The project financial analysis on page 136 of Exhibit A-21 Confidential shows the project costs but no financial benefits and a negative Cost/Benefit ratio of negative 1.0, meaning the project is not financially justified.

Q. DID THE COMPANY IDENTIFY THE CURRENT STATUS AND PHASE OF DEVELOPMENT OF THE NEW SAP-ERP PROJECT?

A. Yes. In response to discovery, the Company stated that the project is currently in the Investment Planning phase and planned to issue a Request for Proposal (RFP) to different

[76] Id.
[77] U-21806 Exhibit AG-28 CONF includes DR AG-CE-0851.

vendors in May 2025.[78] Although the Company seems to have a high preference to stay with SAP to simplify the conversion to the new system, it is not clear yet who the winning bidder will be and which system the Company will ultimately select to implement and at what cost.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE COMPANY PROPOSED IMPLEMENTATION OF A NEW ERP SYSTEM?

A. From the discussion above, it is clear that the current ERP system still functions well and meets the operating needs of the Company. The option also exists for the Company to continue to operate the system into 2030 and potentially past that date with system support by SAP. The Company still has not selected a vendor for the new ERP system and will likely undertake the evaluation of the optimal system to purchase in the second half of 2025. From various aspects, it is premature to include any capital expenditures in this rate case and to defer large forecasted O&M costs in a regulatory asset without firm plans for project execution.

Therefore, I recommend that the Commission remove the [Begin Conf] [redacted]

[78] U-21806 DR AG-CE-0622d (U-21806 Exhibit AG-28 CONF) and U-21806 DR AG-CE-0625 in U-21806 Exhibit AG-29.
[79] U-21870 Stacey Baker testimony at 102.

[redacted]

[redacted] [End Conf].

3. ARP-Field Device Asset Management

On page 5 of Exhibit A-22 (SHB-7), the Company shows projected test year capital expenditures for ARP-Field Device Asset Management assigned to the electric business of $4,850,461. This amount is approximately double the amount allocated to the electric business in 2024 and 2025. In discovery, the Attorney General asked the Company to provide the same historical information in Exhibit A-22 for years 2021, 2022, and 2023. The Company was also asked to explain the large increase in expenditures for the projected test year. In response, the Company provided the requested information and explained that the number of devices is refreshed on a four-year cycle.[80] That would mean that the previous cycle was in either 2022 or 2023 in order for the next refresh cycle to fall in 2026 or 2027. The projected test year includes 8 months from 2026 and four months from 2027. The cost data provided by the Company shows that for 2022 the electric business was only assigned $1,678,000 of the expenditures and in 2023 $2,224,000. Those amounts are less than half the amount that the Company has included in the projected test year in this rate case. The Company reasoning that capital expenditures are increasing in the projected test year due to the four-cycle replacement does not stand up to scrutiny and is not credible.

[80] Exhibit AG-31 includes DR AG-CE-0603 with attachment.

To develop a reasonable forecast for the bridge period, I used the average capital spending in this area from the most recent three historical years from 2022 to 2024 of $2,218,000, prorated it to 16 months and applied the inflation factor of 2.9% to arrive at forecasted capital expenditures of $2,957,000.[81] This amount is $1,039,000 lower than the Company forecasted amount of $3,996,000.[82] I recommend that the Commission remove the $1,039,000 from the Company's forecasted capital expenditures for the bridge period.

Similarly, for the projected test year, I inflation adjusted the annualized bridge period amount of $2,282,000 by the 2.4% inflation rate to arrive at a forecasted capital expenditures amount of $2,337,000.[83] This amount is $2,513,000 lower than the Company's forecast of $4,850,000. I recommend that the Commission remove the $2,513,000 from the Company's forecasted capital expenditures for the projected test year.

E. Capital Expenditures - Summary

Q. WHAT IS THE ATTORNEY GENERAL OVERALL RECOMMENDATION REGARDING THE LEVEL OF CAPITAL EXPENDITURES?

A. The chart below summarizes my proposed capital expenditure in those areas where the level of capital expenditures presented by the Company is excessive and unnecessary.

[81] $2,218,000 x 16/12 x 1.029 = $2,957,000.
[82] 2025 Company forecast $2,218,000 + 4 months of 2026 of $5,305,000 ($7,687,992 x 69% = $3,996,000.
[83] $2,218,000 x 1.029 x 1.024 = $2,337,000.

Summary of AG Disallowed Capital Expenditures	
	Amount (millions)
Distribution Plant	$ 643.5
Power Generation	90.3
Operations Support	62.1
Information Technology	80.9
Total	**$ 876.8**

Therefore, the Commission should reduce the Company's proposed capital expenditures by $876.8 million and reduce average rate base by $679.1 million, including working capital adjustments, as shown in Exhibit AG-32 Confidential. The resulting effect of the lower rate base from the reduction in capital expenditures is a reduction in the revenue deficiency of $55 million.

IV. Depreciation Expense

Q. PLEASE DISCUSS THE DEPRECIATION EXPENSE ADJUSTMENT THAT YOU PROPOSE.

A. In Exhibit AG-32, I identified the adjustments to be made to the Company's proposed capital expenditures. Those reductions lower the amount of depreciation expense that the Company will incur during the projected test year. On the same exhibit, I calculated the reduction in depreciation expense of $28 million. I recommend that the Commission reduce the Company's depreciation expense by this amount for the projected test year.

V. Property Tax Expense

Q. PLEASE DISCUSS THE PROPERTY TAX EXPENSE ADJUSTMENT THAT YOU PROPOSE.

A. As discussed above, I identified the adjustments to be made to the Company's proposed capital expenditures in Exhibit AG-32. Those reductions lower the amount of property tax expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in property tax expense of $4.0 million. I recommend that the Commission reduce the Company's property tax expense by this amount for the projected test year.

VI. Working Capital

Q. THE COMPANY PROPOSED $2.126 BILLION OF WORKING CAPITAL IN THIS CASE.[84] DO YOU AGREE WITH THIS LEVEL OF WORKING CAPITAL?

A. No. I recommend three changes in the working capital level, which total $74.0 million. These changes reduce the amount of Working Capital amount from $2.126 billion to $2.052 billion. The first change reduces the Company's cash balance by $41.4 million. The second change adjusts the level of accrued taxes for a reduction in working capital of $30.0 million. The third change removes $2.6 million of working capital for cloud

[84] See Exhibit A-12 (PDD-34), Schedule B4

computing deferred costs for the SAP S/4 HANA project. These changes are summarized on Exhibit AG-33.

Q. PLEASE EXPLAIN YOUR PROPOSED DECREASE OF $41.4 MILLION TO THE COMPANY'S FORECASTED CASH BALANCE.

A. As shown in Exhibit A-12 (PDD-34), Schedule B-4, the historical cash balance for 2024 was $36.4 million. The Company proposes to increase this recent average cash balance by an additional $14.0 million to arrive at the projected test year cash balance of $50.4 million. According to Mr. Bleckman's direct testimony on pages 38 to 43, the Company believes it appropriate to continue with cash on hand for rate case purposes at an assumed ratio of 1% of cash on hand to revenues. This 1% "rule of thumb" originated from an analysis the Company performed a few years ago for a group of utilities. However, there are several problems with this approach and there is nothing in Mr. Bleckman's testimony to support the 1% cash level. Instead, he attempts to justify this level by pointing to the Company's consistent use of the 1% level in rate cases and points out that the Company held higher cash levels in 2020 due in part to the COVID pandemic and the Company's early issuance of debt. The problems with the use of a 1% cash level are noted below.

First, it is important to point out that sizable amounts of existing cash in the Company's historical periods simply end up in short-term investments bearing interest to pad the Company's bottom line. I discuss this topic further below.

Second, cash on hand is not used to pay for revenues. It is used to pay operating expenses, capital expenditures, and dividends to the parent company. Therefore, the 1% ratio that the Company has calculated based on revenues has no logical connection to the need to keep cash on hand. Third, utilities maintain different levels of cash on hand during different months of the year depending on their seasonal needs for cash to pay for operating expenses and construction costs.

Fourth, every utility has different short-term borrowing facilities and different practices as to how they use or do not use them and may retain more or less cash on hand depending on those circumstances. Therefore, using an average ratio of cash on hand to revenues at a specific point in time does not take into consideration the unique aspects of a particular utility. Fifth, the analysis that the Company performed to arrive at the 1% ratio was based on cash reported by the other utilities in the financial statements. Those cash balances included cash invested in short-term securities under generally accepted accounting practices (GAAP). The Commission does not allow those short-term cash investments with interest bearing securities in the calculation of cash on hand for inclusion in working capital. Therefore, the 1% is likely inflated and inapplicable for ratemaking in a Michigan rate case.

In his testimony in this rate case, Mr. Bleckman implies that in past rate cases, the Commission reconfirmed the use of the 1% ratio. However, a more thorough review of the order in Case U-21389 shows that the Commission seemingly is not wedded to the Company's approach by stating:

> The Commission agrees that Consumers' 13-month average method is consistent with past approvals of methods to determine cash balances and is reasonable given the abnormal disruption in the company's typical cash balance. See, 4 Tr 627-628, 795-800. However, the Commission notes that while it finds that the circumstances described by Consumers in this case constitute an abnormal disruption, the Commission will continue to evaluate the facts and circumstances of each rate case to determine whether deviation from the historical period is appropriate.[85]

In Case U-21585, I provided evidence that the Company has had a propensity in recent rate cases to forecast cash balances that are well above the actual cash that the Company ultimately keeps on hand, which inflates rate base and allows the Company to earn a return on non-existing cash holdings. Although in that rate case, the Commission decided to accept the Company's proposed cash balance, it made it clear that a different approach may be in order in future rate case by stating:

> Nevertheless, considering the company's actual cash balance amounts in recent years, as illuminated by the Attorney General, and the Commission's evaluation of the facts and circumstances surrounding this issue on a case-by-case basis, the Commission finds it appropriate for Consumers to provide further and a more specific explanation in its next electric rate case as to why the company's approach to determining its cash balance remains appropriate and should continue to be approved.[86]

In line with the Commission order, I propose in this rate case to use the average cash balance that the Company actually held over the past three years based on the 13-month average cash balances at the end of each year 2022, 2023, and 2024. This three-year approach provides a normalized average of the cash needs of the Company over the most recent three years and is specific to the Company and its needs for cash on hand. As shown in Exhibit AG-34, the three-year average of cash on hand held by the Company was $25.1

[85] Case No. U-21389, MPSC order dated March 1, 2024.
[86] Case No. U-21585, MPSC order dated March 21, 2025 at page 213.

million, which is $25.3 million lower than the amount forecasted by the Company in this case. Moreover, the $25.1 million cash level noted above includes an average level of cash invested in interest bearing securities of $16.1 million as further supported by the Company's analysis provided in response to discovery and summarized on my exhibit.[87] Therefore, the net cash required to operate the Company's electric business is approximately $9.0 million. This is the amount of cash on hand that I propose in this rate case as further supported in Exhibit AG-34.

Therefore, I recommend that the Commission reject the Company's 1% ratio calculation approach and instead adopt my proposed cash balance of $9.0 million for the projected test year and remove $41.4 million from the Company's forecasted working capital and rate base in this rate case. To do otherwise, the Commission would be inviting the Company to further expand it cash investing activities to the benefit of the Company and at the expense of customers.

Q. PLEASE EXPLAIN THE COST TO CUSTOMERS OF A HIGHER CASH BALANCE AND HOW IT BENEFITS THE COMPANY.

A. Assuming that an extra $20 million of cash is included in working capital in this case, rate base is increased by $20 million and multiplied by the pre-tax cost of capital of approximately 7.5% results in a $1.5 million cost to customers ($20 million x 7.5%), which is reflected in rates. This amount is a benefit to the Company because it is collected in

[87] Exhibit AG-34 includes DR AG-CE-0456.

rates and the cash is not actually maintained on hand and instead invested in short-term securities, as the historical evidence discussed above shows. If the Company invests the $20 million in short-term investments at a 3% interest rate it earns an additional amount of $0.6 million ($20 million x 3.0%) for a total benefit of $2.1 million ($1.5 million + $0.6 million). Clearly, the current process of setting a higher cash balance in working capital benefits the Company in a significant way, but it comes at a cost to customers.

Q. ON PAGE 41 OF HIS TESTIMONY, MR. BLECKMAN POINTS TO A HIGHER CASH BALANCE AS ENHANCING LIQUIDITY TO PROTECT AGAINST UNUSUAL EVENTS SUCH AS COVID-19 OR THE 2022 SPIKE IN GAS PRICES OR HIGHER STORM RESTORATION COSTS. HOW DO YOU RESPOND?

A. Cash on hand does not solve the liquidity problems that arise from the type of events that Mr. Bleckman identified. It is access to short-term credit facilities that is critical in solving large cash needs. For example, in 2022 during the spike in natural gas prices, the Company increased its credit lines from $1.1 billion to $1.8 billion to meet additional cash needs.[88]

In discovery, the Attorney General asked the Company if it had encountered any problems in arranging for short-term credit in recent years to address liquidity issues. In response, the Company stated that it was "…not aware of any instance in which it was directly refused short-term credit…"[89] What should be clear to the Commission is that problems

[88] See the Company's SEC filings on Form 10-K for the periods ending December 31, 2021 and 2022 on page 123 in each case.
[89] DR AG-CE-0457.

involving hundreds of millions of dollars cannot be solved by holding an extra $40 million in cash. Also, to the extent that liquidity issues are smaller, the Company can always draw on its bank lines or from issuing commercial paper.

Accordingly, the Commission should establish a $9.0 million cash balance in this case and reduce Working Capital by $41.4 million.

Q. THE COMPANY PROPOSES A $30.0 MILLION REDUCTION TO ACCRUED TAXES WHICH INCREASES WORKING CAPITAL BY THE SAME AMOUNT. PLEASE EXPLAIN YOUR VIEW ON THIS MATTER.

A. In discovery, the Attorney General asked the Company to explain why Accrued Taxes would decrease when the rate relief requested in this rate case would increase taxable income and thus Accrued Taxes. In response, the Company stated that "the Company's Accrued Taxes for the projected test year does not include additional income from rate relief requested in this case." [90]

The Company's assumption of no new rate relief from this rate case is an unrealistic assumption and the Company's calculation of Accrued Taxes is therefore seriously flawed. In the Company's most recent electric rate case (Case No. U-21585), the Company received 51% of the amount requested or approximately $154 million annually. Although this percentage could be used to recompute Accrued Taxes at a higher level, a more

[90] DR AG-CE-0459.

conservative approach would be to use actual Accrued Taxes from the historical 2024 period.

Accordingly, I recommend that the Commission use the historic balance of Accured Taxes of $286.1 million for the projected test year and reduce Working Capital by $30.0 million.

Q. PLEASE DISCUSS THE ADJUSTMENT TO WORKING CAPITAL THAT YOU PROPOSE REGARDING THE SAP S/4HANA PROJECT.

A. In column (m) of Exhibit A-12 (PDD-34), Schedule B-4, the Company included an increase of $2,576,000 to the projected test year working capital pertaining to the deferral of cloud computing costs for the SAP S/4 HANA project. As discussed in the IT Capital Expenditures section of my testimony, I recommend that capital funding of the SAP S/4 HANA project and related costs be rejected at this time because the project is still in the early phase of development and premature to include in rate base. The same is true with the cloud computing costs pertaining to the SAP S/4 HANA project. Furthermore, in response to discovery the Company stated that it did not have a contract in place for the SaaA solution that would support the cloud computing costs.

Therefore, I recommend that the Commission remove the $2,576,000 from the projected test year working capital.

VII. Capital Structure and Cost of Capital

A. CAPITAL STRUCTURE

Q. WHAT IS THE CAPITAL STRUCTURE YOU RECOMMEND FOR USE IN THE OVERALL RATE OF RETURN CALCULATION?

A. I recommend that the capital structure shown on page 1 of Exhibit AG-33 be used in this case. The first three lines show the projected long-term debt, preferred equity and common equity capital of the Company, which represents the permanent capital structure for the test period ending April 2027. The capital balances in this exhibit reflect the amounts shown in Exhibit A-14 (MRB-1), Schedule D1, with an adjustment to rebalance the capital structure. I increased the long-term debt component in Exhibit AG-33 by $207 million and reduced the common equity component by the same amount. The result is a capital structure with 50% of common equity and 50% of debt and preferred stock.

Q. WHY DID YOU INCREASE LONG TERM DEBT BY $207 MILLION AND OFFSET THIS CHANGE WITH LOWER COMMON EQUITY?

A. The Company has proposed a permanent capital structure with a common equity component of 50.75%. This level of common equity exceeds the 50% equity ratio approved by the Commission in the Company's last two fully contested rate cases, Case Nos. U-21585 and U-21389.[91] The capital structure in this rate case should similarly

[91] Case No. U-21585 Commission order dated March 21, 2025 and Case No. U-21389 dated March 1, 2024. In Case No. U-21389, the Commission approved an equity ratio of 50.02%.

mirror the common equity ratio last approved on March 21, 2025 of 50%. As discussed in my testimony below there are several factors that clearly support a 50% common equity level.

These factors include (1) the Commission's consistent directive in the Company's prior electric and gas rate cases, which stated that a 50/50 capital structure is desirable and appropriate to ensure reduced costs to customers and maintain the Company's strong financial position, unless the Company can demonstrate that a higher ratio is justified; (2) The Company's strong cash flow to debt coverage ratio and credit ratings; (3) the Company's common equity capital contributions by the parent company, albeit often funded with long term debt issued at the parent company level; (4) the favorable regulatory environment in Michigan supported by historical returns on common equity above industry averages and in the top tier of the Company's peer group; and (5) the fact that the common equity ratio of the peer group, used to assess the cost of common equity in this case, is approximately 42%.[92]

Q. PLEASE EXPLAIN YOUR ASSESSMENT OF THE COMMISSION'S DIRECTIVE TO THE COMPANY TO REBALANCE ITS CAPITAL STRUCTURE TO EQUAL AMOUNTS OF DEBT AND EQUITY CAPITAL.

A. The Commission in its order of February 17, 2017 in Case No. U-17990 stated:

[92] Exhibit AG-38 shows that the equity ratio for each peer company and the peer group average ratio of 42.2%.

> The Commission expects that Consumers will have arrived at, or will present a strategy to return to, a balanced structure within the five-year infrastructure plan time period. If Consumers is unable to do so, a more complete analysis should be included to explain why such a result is reasonable and prudent.

In subsequent litigated rate cases, the Commission continued to remind the Company of this directive as it led the Company slowly toward a more balanced capital structure.

Q. WHAT POSITION DID THE COMMISSION TAKE IN THE COMPANY'S MOST RECENTLY CONTESTED RATE CASE ON THE CAPITAL STRUCTURE?

A. In the recent March 21, 2025 order in Case No. U-21585, the Commission decided to set the common equity ratio at 50%, as recommended by the Administrative Law Judge (ALJ) and supported by the Attorney General and other parties. On page 129 of the order, the Commission stated the following:

> Given the above, the Commission adopts the thorough and well-reasoned findings and recommendations of the ALJ. The Commission finds that the balanced capital structure most appropriately balances the interests of the utility's investors and customers, consistent with the holdings in Bluefield and Hope. As such, the Commission adopts a balanced capital structure of 50% debt to 50% equity, utilizing the Attorney General's methodology. See, PFD, pp. 310-311.

In its testimony in this rate case, the Company has not provided any new evidence or persuasive arguments as to why the Commission should veer from its stated goal of a 50/50 debt/equity capital structure for the Company.

Q. IN THE MOST RECENT MOODY'S CREDIT REPORT COVERING CONSUMERS ENERGY, WHAT ARE THE REPORTED CASH FLOW TO DEBT RATIO RESULTS?

A The most recent Moody's report of May 2025 shows the Company's performance under [Begin Confidential] [redacted] ,[End Confidential] all of which are above the 18% downgrade threshold level.[93]

Q. WHAT DID S&P STATE IN ITS MOST RECENT CREDIT REPORT ABOUT CONSUMERS ENERGY'S CREDIT PROFILE?

A. The S&P August 20, 2024 credit report on the Company states "Michigan's regulatory construct is above average compared to peers." The report also points to the streamlined 10-month rate case process, as well as the power supply and natural gas cost rider adjustments, which help the Company to earn its authorized ROE. S&P also notes that the Company's senior secured debt is rated as "A" by S&P (the middle of the "A" category).[94]

Regarding the cash flow coverage ratio, page 3 of the S&P report under the section "Downside Scenario" states:

> We could lower our rating on CE if its stand-alone financial measures weaken such that its FFO to debt weakens to consistently below 15% or we lower our rating on parent, CMS Energy Corp.[95]

However, page 5 of the report shows that the coverage ratio was 17.6% for 2023. S&P also estimated this ratio in the range of 18.3% for 2025 and 2026. These coverage ratios

[93] Exhibit AG-47 includes DR AG-CE-0444 with the Moody's credit report dated May 29, 2025 with ratio data shown.
[94] Exhibit AG-48 includes DR AG-CE-0444 and the S&P report dated August 20, 2024
[95] S&P's FFO to debt ratio is similar to the Moody's cash flow ratio "CFO Pre W/C referred to earlier.

are not indicative of any concerns about a possible debt rating downgrade and are well above the 15% threshold set by S&P. On page 3 of the report, S&P states that the Company's credit metrics were weak in 2023 largely due to weather-related issues which they characterize as "mild sales and convective [higher] storm activities." S&P clearly understood that the decline in the coverage ratio in 2023 was temporary and not reflective of any long-term decline trends.

In 2023, the Company reported net income of $865 million and a return on equity (ROE) of 8.25% versus its authorized ROE of 9.90%. The lower net income and cash flow temporarily reduced the coverage ratio. In 2024, the Company reported an increase of 16% in net income to over $1.0 billion, or an increase of $142 million over 2023. The Company's earned ROE also increased to 9.1%.[96] As discussed in more detail below, the increase in profitability nearer to the authorized ROE will boost the cash flow to debt coverage ratio.

Q. ON PAGE 15 OF HIS TESTIMONY, MR. BLECKMAN SATES THAT "THE COMPANY'S FFO TO DEBT RATIO AS CALCULATED BY MOODY'S IS TRENDING DOWN…WELL BELOW THE LOW END OF MOODY'S EXPECTED RANGE…" DO YOU AGREE WITH THAT STATEMENT?

[96] Based on total Consumers Energy reported net income of $1.007 billion and average common equity of $11,078.5 billion in the 2024 Form 10K.

A. No. First, as reported above, none of the Moody's historical cash flow ratios are below the 18% Moody's downgrade threshold. Second, Mr. Bleckman fails to explain the unusual and short-term issues faced by the Company in 2022 and 2023, and mischaracterizes the situation in an attempt to mislead the Commission. The cash flow to debt ratio declined somewhat in 2022 due to a temporary increase in natural gas prices in 2022, which required the Company to incur larger short-term borrowings. In 2022, higher gas prices increased the cost of gas purchases and gas inventories. This in turn caused the Company to take on more debt which in turn reduced net income and increased the debt denominator in the calculation of the coverage ratio.

Gas inventory levels increased from $462 million in December 2021 to $840 million in December 2022. This increase of $378 million in gas inventory required more temporary debt financing for the year. The temporary increase in debt receded in 2023 and 2024. Page 2 of Exhibit AG-44 shows that if we adjust for this temporary phenomenon the Moody's FFO to Debt ratio would have been 20.9% instead of the actual result of 20%.

Temporary events from year to year can have either a positive and negative effect on earnings, cash flow, short-term debt, and the cash flow to debt coverage ratio. However, rating agencies look past those temporary issues and focus on the long-term financial health of the Company.

Also, for the most recent 12-month period ended March 2025, shown in the Moody's report of May 29, 2025, the Company's results reflect a [Begin Confidential] [redacted] [End

Confidential] cash flow ratio.[97] The ratio reflects the Company's decision during the 12-month period to lower the common equity capital ratio to 48.4%, which is below the 50% previously approved by the Commission, and increase the long-term debt ratio to 51.4%.[98] As shown on page 1 of Exhibit AG-44, had the Company maintained a 50% common equity ratio, it would have achieved a cash flow coverage ratio of 20% instead of 19.4%.

Q. DID YOU CALCULATE THE IMPACT ON THE MOODY'S CASH FLOW TO DEBT COVERAGE RATIO BASED ON A 50% EQUITY RATIO IN THE COMPANY'S CAPITAL STRUCTURE AND AN AUTHORIZED ROE OF 9.80%?

A. Yes. On page 1 of Exhibit AG-44, I calculated the Company's key cash flow to debt ratio for the 12 months ended March 2025 adjusted for the ROE and Common Equity ratio levels I advocate in this case. I start with Moody's actual results for the year ended March 2025 and adjust them to reflect a 9.80% ROE and a 50% common equity ratio. I chose this year ending in March 2025 because this is the most recent information available from Moody's.

For my analysis of actual cash flow ratio results, I started with the actual year ended March 2025 data on line 1 of Exhibit AG-44 page 1. Next, on line 2, I adjust the capitalization to reflect a balanced capital structure. This increases common equity and decreases long-

[97] Exhibit AG-47 CONF includes Moody's May 29, 2025 report.
[98] Sourced from the Company's Form 10-Q Financial Statements of March 31, 2025 and 2024.

term debt. On line 3, I adjusted the cash flow downward to reflect a 9.80% ROE instead of the 10.16% ROE reported in the year ended March 2025 period. The result of these adjustments is shown on line 4 with a cash flow to debt ratio of 20.0%. This ratio is well above the 18% downgrade threshold noted by Moody's in its most recent report.[99] I have not presented any ratio results for S&P since the ratio calculations are highly similar and the S&P downgrade threshold is lower at 15%.

I will point out that by starting with actual Moody's year-ended March 2025 results, items such as leases and short-term debt are already reflected in the cash flow and debt elements, which determine the ratio. The Company often points to these as being "add-ons" which are not considered in the permanent capital on a ratemaking basis. However, these are two separate calculations for different purposes and should not be confused with one another.

In summary, my analysis shows that the 9.80% ROE and 50% common equity ratio would result in the Company's cash flow ratios being well above the long-term threshold levels that would result in a credit downgrade.

Q. DO THE RATING AGENCIES' CURRENT BUSINESS AND CREDIT OUTLOOK FOR THE COMPANY SHOW ANY SIGNIFICANT CONCERNS?

A. No. S&P in its August 2024 report provides the following outlook for the Company:

> The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid

[99] Moody's expectation of a cash flow coverage ratio of "18% on a sustained basis." Page 2 of May 29, 2025 report in Exhibit AG-47.

> increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of 17%-19%.[100]

Similarly, in its May 29, 2025 report, Moody's provides the following rating outlook:

> The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. The stable outlook also incorporates our view that Consumers Energy will maintain prudent financial policies while managing through its robust investment cycle and that debt levels at the parent will not increase materially.[101]

Fitch Investor Service provided the following summary of the Company's credit profile in its April 16, 2024 report:

> Constructive Regulatory Environment: Fitch believes the regulatory environment in Michigan under the Michigan Public Service Commission (MPSC) remains mostly constructive from a credit perspective. The regulatory framework allows for full pass-through of fuel costs and purchased power, forward-looking test years and a timely 10-month review period for general rate case resolution. Furthermore, Consumers Energy's authorized ROE of 9.9% compares favorably with industry averages. Increasing storm activity in Michigan and resultant power outages have attracted regulatory focus on reliability. In March 2023, the MPSC tightened performance standards for utilities by way of enhanced outage credits, and updated reliability standards. An MPSC-led straw proposal for additional potential financial incentives and disincentives has also been underway since August 2023. In Fitch's view, the risk of performance-based penalties is manageable within Consumers Energy's current credit profile. Fitch also does not expect a material negative outcome in the pending audit ordered by MPSC in October 2022 to assess the compliance of Consumers Energy with storm outages and safety regulations during the 2021 storms in Michigan. The final audit report is expected in summer 2024.[102]

The credit reports provide a favorable outlook of the Company's credit profile contrary to Mr. Bleckman's bleak predictions.

[100] Exhibit AG-48 CONF includes S&P August 20, 2024 report.
[101] Exhibit AG-47 CONF includes Moody's May 29, 2025 report
[102] Exhibit AG-49 CONF includes Fitch Investor Service April 16, 2024 report.

Q. PAGE 19 OF MR. BLECKMAN'S TESTIMONY STARTS A SECTION TITLED "RATING AGENCIES ASSESSMENT OF THE REGULATORY ENVIRONMENT" AND HE CITES PUBLISHED INFORMATION FROM BOTH STANDARD & POOR'S AND UBS. WHAT ARE YOUR VIEWS OF THIS INFORMATION.

A. Regarding UBS, this firm ranks regulators in Michigan and 57 other jurisdictions. However, UBS is not a credit rating agency. It is a stock brokerage and investment banking firm among other things. As discussed in the article in Exhibit A-34 (MRB-15), the UBS analysis is concerned with "fair outcomes for investors" and not necessarily creditors or customers. On page 20 of his testimony, Mr. Bleckman states that "It is apparent that rating agencies and analysts are taking note of the Company's regulatory outcomes and are viewing them unfavorably". It appears that he is drawing that conclusion from the UBS report. The article by UBS does not address any specific regulatory outcomes or concerns related to Consumers Energy or CMS Energy. Moreover, the article was published in May 2023 and is now more than two years old. This is old information provided by witness Bleckman which he mischaracterizes.

Q. ON PAGE 20 OF HIS DIRECT TESTIMONY, MR. BLECKMAN ALSO REFERS TO EXHIBIT A-35 (MRB-16), WHICH IS AN S&P REPORT NOTING NEGATIVE CREDIT TRENDS IN THE UTILITY INDUSTRY. DO YOU BELIEVE THAT THIS REPORT IS DIRECTLY APPLICABLE TO CONSUMERS ENERGY?

A. No. The quoted information from the report noted on pages 21 and 22 of Mr. Bleckman's testimony is fairly generic. The key areas of concern on page 11 of the report, which Mr. Bleckman omitted, are higher interest rates, changes to inflation, delays of offshore wind projects, and rising taxes. On pages 7 and 8, the S&P report also points to concerns with wildfire risks for utility companies west of the Mississippi River.

Most of these risks do not apply to the Company. First, CMS Energy and Consumers have no off-shore wind projects. Second, the projected test year ratemaking construct used in Michigan permits utility companies to recover projected costs and CPI inflationary increases for O&M expenses and capital expenditures in setting new rates. Third, regarding "higher interest rate risk", most of the Company's debt is long-term fixed-rate debt with only seasonal short-term debt which are forecasted for the projected test year and included in rates. In contrast, other utilities may use significant short-term debt and do not have a projected test year cost recovery mechanism. As such, the Company is in a superior position on this issue relative to other utilities.

Fourth, S&P's concerns with the potential higher tax rates at this time appear to be a minor risk. No federal legislation is currently being considered that would increase the corporate income tax rate. Interestingly, S&P points out the Alternative Minimum Tax (AMT) provisions of the Inflation Reduction Act as a possible concern for larger utility companies. However, it goes on to indicate '…we expect that most fully integrated large utilities…will use their renewable tax credits to minimize or eliminate AMT…" Accordingly, no concerns are warranted in this area.

In summary, the Commission should dismiss the generic utility industry concerns raised by Mr. Bleckman and described in the S&P report, as inapplicable to the Company's regulatory and financial position.

Q. ON PAGE 21 OF HIS TESTIMONY, MR. BLECKMAN POINTS TO S&P'S JANUARY 2025 "INDUSTRY CREDIT OUTLOOK 2025" WHICH HE SPONSORS AS EXHIBIT A-40 (MRB-21). HE POINTS TO CERTAIN S&P CONCERNS RAISED AS BEING WORTHY OF THE COMMISSION'S ATTENTION. WHAT IS YOUR ASSESSMENT?

A. First, it is worth noting that page 8 of this publication includes a map showing all of the 50 United States based on S&P's Regulatory Assessment ranking in each case. Michigan and five other states rank highest as being "Most Credit Supportive". Second, the article raises three key concerns which are (a) the need for more common equity in the industry; (b) potential tax legislation which could adversely affect the industry; and (c) robust capital spending. In general, the potential for adverse federal corporate tax legislation does not seem to be a concern for the foreseeable future. The applicability of other two items vary from utility to utility depending on their circumstances. Regarding additional common equity, as discussed above, a balanced capital structure with 50% common equity provides a strong financial position for the Company to continue to raise new capital to address spending on infrastructure improvements. The high level of capital spending obviously concerns S&P and the Company should try to moderate the projected spending by taking a more gradual escalation in its forecasted capital expenditure in future years.

Q. **YOU STATED EARLIER THAT COMMON EQUITY CAPITAL INFUSIONS INTO CONSUMERS ENERGY BY THE PARENT COMPANY ARE BEING FUNDED TO SOME EXTENT BY LONG TERM DEBT. PLEASE EXPLAIN.**

A. There are several issues in the financial transactions between Consumers Energy and its parent company, CMS Energy ("CMS"), which cannot be ignored when analyzing the Company's proposed capital structure. First, CMS can make the Company's common equity ratio whatever it wants. The same executive management that runs CMS Energy also operates the Company. Management can direct at any time how much in capital it wants to inject into the Company from the parent company and call it equity capital. In fact, it has done just that over the years. In response to a discovery request, the Company has stated that the injection of common equity from CMS Energy is at the discretion of management with no approval from the Board of Directors.[103] Such freedom to call for equity capital would not exist if Consumers Energy itself was a publicly traded company.

Over the five years 2020 to 2024, Consumers Energy's Common Equity has increased from $7.7 billion at year end 2019 to $11.4 billion in 2024, which is an increase of $3.7 billion. An analysis of the Company's financial statements filed with the Securities and Exchange Commission shows that the $3.7 billion increase is due to the following factors:

[103] CECo response to discovery request U-18322-AG-CE-439.

Table 1			
Consumers Energy			
Common Equity Change for Five Years (Dec. 2020 - 2024)			
			$ Billions
1	Net Income of Consumers Energy	$	**4.5**
2	Dividends Paid to CMS		**(3.6)**
3	Return of Capital		**(0.3)**
4	New CMS Investment in Consumers Energy		**3.1**
5	**Total Change in Common Equity**	$	**3.7**

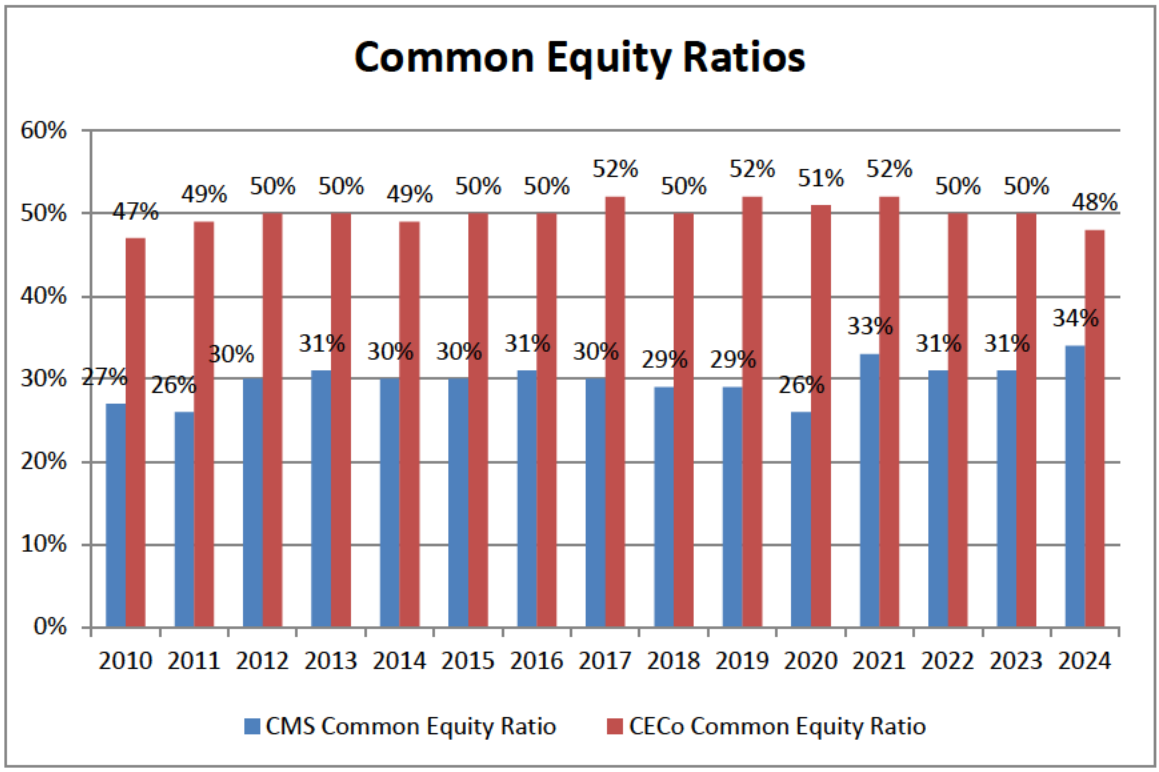
First, as shown in table 2 below, of the $3.1 billion of new equity invested by CMS into Consumers, $1.7 billion (or 55%) is from new CMS debt (line e versus line g).

Table 2			
CMS Energy			
CMS Funds Available to Invest in Consumers Energy (Dec. 2020 - 2024)			
			$ Billions
a.	Dividends From Consumers Energy	$	**3.6**
b.	Less: Dividends to CMS Shareholders		**(2.7)**
c.	CMS Net Equity Issued		**0.8**
d.	Increase in CMS Equity Capital		**1.7**
e.	Increase in Parent Company Debt		**1.7**
f.	Other CMS Changes		**(0.3)**
g.	**Funds From CMS Invested in Consumers Energy**	$	**3.1**

Second, to further support my point, CMS Energy is a frequent issuer of long-term debt in the capital markets. Over the last five years, CMS parent-only debt increased $1.7 billion

from $3.3 billion at year end 2019 to $5.0 billion at year end 2024.[104] Yet the only substantive business CMS Energy owns is Consumers Energy.

The following chart displays the gap in equity capital between Consumers Energy and CMS over the years 2010 to 2024. While cash raised from the issuance of long-term debt at CMS is not immediately injected into Consumers Energy, it is nonetheless being utilized in part to fund CMS's so-called equity infusions into CECo.



[104] From SEC filings on Form 10-K for the years ended 2020 (p. 124) and 2024 (p. 123).

It is important to remember that nearly 95% of CMS' assets and revenue come from Consumers Energy.[105] Therefore, from a practical operating standpoint, CMS and Consumers Energy are one and the same.

My analysis clearly shows that CMS is using a form of double leverage by using debt capital to make its equity infusions into Consumers Energy. Although a strong argument could be made that the common equity capital of the Company should be less than 50% given the evidence I have presented, the Commission certainly should not permit a capital structure with common equity capital above 50%.

From the statements in Moody's credit reports and similar concerns expressed by other rating agencies, it appears that the debt-laden capital structure of CMS has contributed to a lower debt rating than the Company could have achieved if CMS was capitalized with more equity capital. For example, on page 1 of the May 31, 2023 credit report, Moody's states:

> Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). However, CMS has made notable progress in reducing the percentage of parent debt in its capital structure over the last 2-3 years. We now estimate that the percentage of parent debt will remain around mid-20% of total consolidated debt.

Similarly, on page 2 of the February 13, 2023 credit report, Fitch Investor Service states:

> There is parent-subsidiary rating linkage between CMS Energy and Consumers Energy. Fitch determines CMS Energy's standalone credit profile (SCP) based upon consolidated metrics. Fitch considers Consumers Energy's SCP to be stronger than CMS Energy's. Emphasis is placed on Consumers Energy's status as a regulated entity. Legal ring-fencing is considered porous given the general protections afforded

[105] CMS Energy 2024 Form 10K at page 171.

> by economic regulation. Access and control are also evaluated as porous. CMS Energy centrally manages the treasury function for all of its entities. However, both the parent and Consumers Energy issue their own long-term debt. Due to the aforementioned linkage considerations, Fitch will limit the difference between the Long-Term Issuer Default Ratings (IDRs) of CMS Energy and Consumers Energy to two notches.

The result has been higher interest costs for customers. Partially to compensate for this significant leverage at CMS, the Company now wants a higher equity ratio in the capital structure that will further increase costs to customers.

Q. **YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP USED TO ASSESS THE COST OF COMMON EQUITY IS APPROXIMATELY 42%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE COMMON EQUITY RATIO FOR THE COMPANY.**

A. As shown in Exhibit AG-38, the average common equity ratio of the peer company group for 2024 was 42.2%. The cost of equity for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure. Thus, it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible, in order to have consistency with the cost of equity capital derived from those peer group companies. The Company's proposed common equity capital ratio of 50.75% creates a disconnect that is not acceptable and is also more costly to customers.

Q. WITNESS BLECKMAN SPONSORS EXHIBIT A-29 (MRB-10) SHOWING THE COMMON EQUITY RATIOS FOR VARIOUS GAS AND ELECTRIC UTILITY COMPANIES SUPPOSEDLY DECIDED IN RATE CASES DURING 2020 TO

2025. THE EXHIBIT SHOWS AN AVERAGE COMMON EQUITY RATIO OF 51.85%. DO YOU FIND THIS EXHIBIT WORTHY OF CONSIDERATION?

A. No. It appears that Mr. Bleckman's purpose in presenting this exhibit showing an average common equity ratio of 51.85% is an attempt to support his recommended 50.75% equity ratio and to suggest that his rate is conservative and very reasonable compared to the equity ratios approved for other utility companies.

The Commission should not rely on the information provided by Mr. Bleckman in Exhibit A-29 because it is neither accurate nor comprehensive to provide a proper context to establish an appropriate common equity ratio for the Company. He presents only selective information. The major flaws are discussed below.

First, the common equity ratio information presented by Mr. Bleckman reflects a number of gas decisions which average to 53.1% while the electric decisions average to 51.5%. The Inclusion of gas decisions inflates the outcome and they should not be used in this electric rate case. Second, Mr. Bleckman has included several small electric utilities in the exhibit. The inclusion of smaller electric companies with higher equity ratios is a significant factor that boosts the overall average equity ratio in Mr. Bleckman's analysis. Smaller utilities tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage.

For example, Kingsport Power on line 9 of the exhibit with its 53.5% ratio serves approximately 50,000 customers in rural Kentucky and Tennessee.[106] Also, Alaska Electric Light & Power on line 13 of the exhibit with a 60.7% equity ratio serves 18,000 customers in an isolated area in Alaska.[107] Southwestern Public Service, shown on lines 49 and 50 of the exhibit, serves 410,000 customers in two states with equity ratios of 54.6% and 54.7% set in each of the two states.[108] Finally, Duke Energy Kentucky with a 54.1% equity ratio on line 24 of the exhibit operates with a $1.8 billion capital base which is less than 6% the size of Consumers Energy with a capital base of $32.4 billion.[109]

Third, some of the data in Mr. Bleckman's exhibit is stale. For example, Alliant Energy's Wisconsin Power & Light unit, listed with an equity ratio of 55.09% on line 2 of Exhibit A-29, now has a 53.7% equity ratio.[110] Similarly, the equity ratio for Duke Energy Progress-NC, listed with an equity ratio of 53% on line 26 of the exhibit, actually has an equity ratio of 50.5%.[111] Fourth, in compiling Exhibit A-29, Mr. Bleckman excluded utility companies in the northeastern part of the United States where ROEs and equity ratios tend to be lower.

In summary, Mr. Bleckman has constructed a selective group of utilities in Exhibit A-29 that are not representative of the electric utility industry and result in an inflated average

[106] Page 1 of American Electric Power 2024 Form 10-K report.
[107] Page 32 of Avista 2024 Form 10-K report
[108] Page 57 of Xcel Factbook from July 2025.
[109] Exhibit A-14, Schedule D1.
[110] Page 37 of Alliant Energy 2024 Form 10-K report.
[111] See Page 15 of the Duke Energy 2024 Form 10-K report

equity ratio. The Commission should disregard the Company's presentation of a misleading industry average equity ratio that is disconnected from the calculations of the cost of equity capital of the companies in the peer group.

Q. WHAT IS THE REVENUE REQUIREMENT SAVINGS RELATED TO A LOWER COMMON EQUITY RATIO OF 50.0% IN COMPARISON TO THE COMPANY'S PROPOSED EQUITY RATIO OF 50.75%?

A. The difference is approximately $9.0 million annually. This reflects (a) the difference between the pre-tax cost of common equity of approximately 14.1% versus the cost of long-term debt of 4.5%; (b) the Company's proposed rate base of approximately $15.4 billion; and (c) the percentage of total capital being shifted from common equity to long term debt.

Q. DID YOU MAKE ANY OTHER ADJUSTMENTS TO OTHER ITEMS INCLUDED IN THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. No. I adopted the other capital balances sponsored by witness Bleckman in Exhibit A-14 (MRB-1), Schedule D1, page 1.

B. COST OF CAPITAL

Q. **WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL ARE YOU RECOMMENDING IN THIS CASE?**

A. I am recommending an overall return on capital of 6.06%, which includes a return on common equity of 9.80%, as shown in Exhibit AG-35, page 1.

Q. WHAT COST RATE DID YOU UTILIZE FOR LONG TERM DEBT?

A. For the long-term debt cost rate, I used a rate of 4.39% which is 0.15% less than the 4.54% rate recommended by witness Bleckman.

The Company anticipated four new long-term debt issuances in 2025 and 2026 (two in each year). The 2025 debt issuances have now been completed with a cost based on net proceeds of 4.46% for one debt issue and 5.22% for the other debt.[112] Mr. Bleckman assumed a 6.32% cost rate for each of these issues as reflected on Exhibit A-14 (MRB-4), Schedule D1 on lines 44 and 45. The lower cost of debt actually issued in comparison to the assumed interest rates used by Mr. Bleckman reduces interest costs by $15.2 million annually (a portion of these savings is applicable to the company's gas business). For the other two debt issues anticipated in 2026, Mr. Bleckman assumed a 6.35% interest rate.

However, this debt cost rate assumes a 4.89% 30-year U.S. Treasury rate in the cost build-up section of Exhibit A-14 (MRB-4), Schedule D1. As discussed below, I used a more recent forecast of the 30-year U.S. Treasury rate of 4.40%, which is 0.49% lower than the rate used by Mr. Bleckman. Accordingly, on page 2 of Exhibit AG-35, I calculated an updated interest rate for the new debt issuances of 5.86% compared to the Company's rate

[112] DR AG-CE-409 including Attachment 1.

of 6.35%, for an additional reduction to the cost of capital. I note that Mr. Bleckman's assumed rate of 4.89% for the 30-year U.S. Treasury rate is above actual U.S. Treasury rates as of September 15, 2025, as well as the lowest 30-year Treasury rate used by Company witness Bulkley for cost of equity purposes of 4.30%.[113]

The lower interest costs from the May 2025 debt issues and the projected savings from the 2026 debt issues that I recommend reduce the revenue deficiency in this case by $10.2 million.

Q. WHAT COST RATE DID YOU UTILIZE FOR PREFERRED STOCK?

A. For the preferred stock, I used a 4.5% rate, consistent with the rate recommended by Company witness Bleckman.

Q. WHAT COST RATE DID YOU UTILIZE FOR SHORT TERM DEBT AND THE OTHER COMPONENTS OF THE CAPITAL STRUCTURE?

A. For Short Term Debt and Deferred Taxes, I used the cost rates recommended by witness Bleckman. Cost rates for JDITC reflect those rates I used for the permanent capital sources.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-35.

[113] Exhibit A-14 (AEB-1) Schedule D-5, pages 7 and 8.

A. To develop the overall cost of capital on line 12, column (f), I have first developed the percentage weighting of each capital component in column (d) by dividing the individual capital balances in column (b) by the total of all capital components in that column. Next, I have multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the values in column (f). The total of the individual values in column (f) is the total cost of capital of 6.06%.

Regarding the pretax weighted cost of capital on line 12, column (h), I multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income and other taxes paid by CECo for calculation of the pretax weighted cost of 7.47% in column (h).

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN DETERMINING THE COST OF COMMON EQUITY FOR THE COMPANY?

A. A utility company is entitled to a fair return that will allow it to attract capital and be sufficient to assure investors of its financial soundness. In its opinion in Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia (the "Bluefield Case") 262 U.S. 679 (1923), the United States Supreme Court indicated that:

> *"A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that being made at the same time…on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under*

efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties…"

The principals of the Bluefield Case were re-affirmed by the U.S. Supreme Court in 1944 in the case FPC v Hope Natural Gas Company, 320 U.S. 591.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON EQUITY IN EXHIBIT AG-36.

A. Determining the cost of common equity for an enterprise or an industry group is inexact since investors can only estimate what the future cash flows from any enterprise may be over time. Because of this uncertainty, most financial experts will not rely solely on any particular method. To determine the cost of common equity, I utilized three approaches to assess this cost. These are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and the Utility Risk Premium approach.

While Exhibit AG-36 shows an average ROE of 9.73% from the three methodologies, I recommend an allowed rate of return on equity of 9.80% for the reasons explained later in this section of my testimony. In connection with these methods for determining the cost of common equity, I have considered the cost of common equity for a proxy group of peer companies.

Q. **PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROXY GROUP OF PEER COMPANIES.**

A. To develop an appropriate peer group, I started with the 38 utility companies followed by the Value Line Investment Survey in its "Electric Utility Industry" sections. I removed seven of these companies due to size considerations with revenues over $20 billion or under $1 billion. I also removed companies with no dividend growth (Dominion Energy and Hawaiian Electric), as well as companies with foreign investment (Sempra, Hydro-One and Fortis). I removed Black Hills, Eversource, Allete, Entergy, NorthWestern Energy, and TXNM Energy due to merger and acquisition (M&A) activity. Finally, I removed eight companies with low growth/no growth in earnings or excessive growth rates that reflected a rebound in earnings from depressed earnings in recent years, exposure to wildfire risk and high risk from offshore wind development, as well as companies with large non-utility operations or less than 50% in electric operations.

Exhibit 42 shows the publicly traded electric utilities considered and the reasons for removing some of the companies to arrive at a peer group of utilities comparable to the Company. The result of this analysis is the group of eleven companies shown in Exhibit 37, all of which have growing earnings and dividends which comprise my peer group.

Q. HOW DOES YOUR PEER GROUP COMPARE TO THE COMPANY'S PEER GROUP?

A. The Company's peer group contains eight of the companies in my peer group.[114] Of the eleven other companies in the Company's proposed peer group three should be removed because of size considerations. Duke Energy, Southern Company, and NextEra Energy have annual revenues of $30 billion, $26.7 billion, and $24.8 billion, respectively. Due to their excessively large size compared to Consumers Energy's $7.5 billion in revenue, these utilities are not an appropriate fit for the Company's peer group. NextEra Energy should also be removed from the peer group due to its significant investments in non-utility power production in several states, representing over 40% of its assets. The Company's proposed peer group also includes Entergy, NorthWestern Energy, and TXNM Energy, which I removed from my proposed peer group because of M&A activity that distorts the dividend yield and earnings growth of these companies. TXNM is involved in the sale of certain assets to Blackstone Infrastructure Company, while Entergy is looking to sell its Louisiana gas distribution properties, and NorthWestern has announced merger plans with Black Hills. The remaining utilities included in the Company's peer group, but not my peer group, should be excluded because of poor earnings history and inconsistent earnings growth rates.

In summary, the Company's proposed peer group includes companies that are not comparable to Consumers Energy and should not be relied on by the Commission in determining an appropriate cost of equity capital in this rate case.

[114] The other three companies in my peer group which were excluded from the CECo. peer group are Consolidated Edison, CenterPoint Energy and WEC Energy.

Discounted Cash Flow (DCF) Cost of Equity Method

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") APPROACH.

A. The DCF approach is based on the proposition that the price of any security reflects the present value of all future cash flows (dividend flows) from the security discounted at a single discount rate which, in the case of common stocks, is the required return on equity. Expressed mathematically, the resulting equation can be reconfigured to solve for the required rate of return and this equation is:

$$R = D/P + g$$

where "R" = the Required Equity Return
"D/P" = the Dividend Yield on the Security
and "g" = the expected growth rate in dividends

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-37. The stock price information in column (c) of this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from June 18 to July 31, 2025. The annual dividend in column (d) is the forecasted average dividend level for 2025 and 2026 as projected by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on (1) the estimate of earnings growth through 2029 per Value Line; and (2) the earnings growth estimates per Yahoo for 2025 and 2026.

The resulting calculation of the DCF Method is an average return on common equity for the proxy group of 9.57%.

Q. PLEASE ASSESS THE RESULTS OF THE DCF ANALYSIS YOU PERFORMED.

A. The DCF analysis relies upon financial market information for the dividend yield portion of the equation. It also relies upon judgments of dividend and earnings growth prospects of security analysts which reflects the consensus of the market on which investors rely. Therefore, I place a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other methods in determining the cost of common equity.

Q. HOW DOES YOUR DCF COST OF CAPITAL ESTIMATE COMPARE TO THE COMPANY'S DCF ESTIMATE?

A. Company witness Bulkley calculated a DCF cost of equity capital of 10.24%, which is 67 basis points higher than the 9.57% DCF result I calculated.[115] The result of the DCF analysis are dependent upon the dividend yield and the average earnings growth rate of the companies in the peer group.

The dividend yield in my analysis is 3.56%, but the Company calculated a higher yield of 3.75%. This accounts for approximately 20 of the 67-basis point difference. Also, the

[115] This Company presents nine different DCF results based on stock prices over 30 days 90 days and 180 days with growth at minimum levels, average levels and maximum levels. The 10.24% DCF ROE rate is shown on page 1 of Exhibit A-14 (AEB-1) and represents a 30-day stock price calculation and average growth.

projected growth rate is higher in the Company's case at 6.48% vs. 6.01% in my analysis, which accounts for the remaining difference of 47 basis points.[116] I will point out that the data on the dividend yield and the earnings growth rates used by the Company were compiled sometime earlier in 2025 and are now stale. The stock prices of the utilities in the peer group are now higher, thereby justifying a lower dividend yield compared to the Company's filed case. The earnings growth rates used by the Company include higher earnings growth rates for Avista, Dominion Energy, and NextEra. As stated above in my testimony, these companies are inappropriate for inclusion in the DCF peer group. In particular, the earnings growth rate of NextEra ranges from 7.11% to 8.50% due in part to its power generation business. Dominion Energy's growth of 10.2% reflects, in part, Dominion's restructuring of its businesses to sell certain gas assets and a 50% interest in its Coastal Wind project. As such, the 10.2% growth rate is a temporary situation. Avista should not be included since this company is now seen as having "Wildfire Risk". This has depressed this company's stock price and inflated its dividend yield.

Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL (CAPM) APPROACH TO DETERMINING THE COST OF COMMON EQUITY CAPITAL.

[116] The 3.75% dividend yield and 6.48% growth rate of the Company's peer group analysis are from page 3 of Exhibit A-14 (AEB-1).

A. The Capital Asset Pricing Model (CAPM) is based on the proposition that the expected return on a common equity security is a function of risk as measured by the "Beta" of that security. In equation form, CAPM is as follows:

$$k_e = R_f + (B \times R_p)$$

where k_e = *The market cost of common equity for a specific security*

R_f = *the "risk free" rate of return*

R_p = *the overall return of the market less the risk-free rate (over several years)*

B = *the systematic risk of a particular common equity security vs. the market*

Q. PLEASE EXPLAIN THE BETA OR "*B*" COMPONENT OF THE EQUATION.

A. This measure of risk reflects the extent to which the price of a particular security varies in relationship to the movement of the overall market. Securities that vary over time more than the overall market will have a Beta that is greater than 1.00. Some securities vary less in price over time than the overall market. In these cases, the Beta will be less than 1.00. Utility stocks tend to move less than the overall market. Reflective of this outcome, the average Beta of my peer group is 0.76.

Q. PLEASE EXPLAIN EXHIBIT AG-38 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-38 shows the results of the CAPM method based upon (1) a 4.40% risk-free rate; (2) the Betas of the companies in the Peer Group taken from Value Line; and (3) the 7.35% historical Market Risk Premium (R_p) return from the years 1926 to 2024.[117]

Regarding the use of a risk-free rate for CAPM purposes, I used a 4.40% rate which is the 30-year U.S. Treasury Bond for the second and third quarters of 2026 sourced from economic projections provided by the Company.[118]

The result of my CAPM approach using the 5.58% adjusted market risk premium (7.35% Risk Premium x 0.76 Beta) plus the 4.40% risk-free rate is a cost of equity capital of 9.98% for the proxy group average.

Q. PLEASE ASSESS THE CAPM APPROACH.

A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios of stocks. As such, it can be useful. However, the key issue with CAPM is that it assumes that the entire risk of a stock can be measured by the "Beta" component. As such, the only risk to the investor is from fluctuations in the overall market. In actuality, investors take into consideration company-specific factors in assessing the risk of each particular security. Therefore, I give the CAPM approach less weight than the DCF approach in determining the cost of common equity.

[117] WP-AG-38A.
[118] Exhibit AG-50 includes DR AG-CE-0398 includes the May 1, 2025 Blue Chip projection showing a 4.40% 30-Year U.S. Treasury rate for the second and third quarters of 2026.

Q. HOW DO YOUR CAPM RESULT COMPARE TO THE RESULTS PRESENTED BY COMPANY WITNESS BULKLEY?

A. Ms. Bulkley presents the results of her projected CAPM and Projected ECAPM methods in Exhibit A-14 (AEB-1), page 1. In the table below, I show the development of Ms. Bulkley's CAPM ROE result compared to mine.

Comparison of CAPM Results

	CAPM Estimate of:	
CAPM Results Simplified	**AG**	**CECo**
Market Risk Premium (MRP)	7.35%	8.28% *
Avg. Beta Factor (B)	0.76	0.78
MRP x B	5.58%	6.49%
Projected 2026 Risk Free Rate	4.40%	4.30%
Total CAPM Result	**9.98%**	**10.79%**

* Results based on a Projected Growth Rate for the S&P 500. See Exhibit A-14 (AEB-1), Sched. D5, page 14.

The key difference is the Company's higher Market Risk Premium, which is discussed below. The Company's ECAPM results are all slightly higher than the CAPM result in the table above due to the approach used. This is also discussed below in my testimony.

Q. PLEASE EXPLAIN THE COMPANY'S DECISION TO USE A 4.30% RATE FOR THE 30-YEAR U.S. TREASURY RATE AS THE RISK-FREE RATE AND YOUR ASSESSMENT REGARDING THE USE OF THIS RATE TO DEVELOP THE ROE ESTIMATES FOR THE PROJECTED TEST YEAR.

A. The Company developed multiple CAPM ROE estimates using 4.61%, 4.52%, and 4.30% Risk-Free rates. The Company's use of multiple rates seems to be a hunt for an approach that will result in a higher ROE rate. The use of the 4.30% 30-year forecasted U.S. Treasury bond rate is particularly flawed because it reflects U.S. Treasury rates forecasts for 2026 to 2030, which in large part includes periods beyond the test year ending October 2026. Instead, I used the single rate of 4.40% for the 30-year U.S. Treasury bond rate forecasted for the second and third quarters of 2026, which is at the outset of the projected test year.[119]

Q. PLEASE PROVIDE YOUR ASSESSMENT OF THE COMPANY'S CALCULATED MARKET RISK PREMIUM OF 8.28%.

A. Instead of using a proven historical market risk premium (MRP), the Company developed its MRP based largely on future expected stock price growth rates and dividends for a select group of companies from the S&P 500 stock index over the next three to five years**.** Based on her sample of companies, Ms. Bulkley calculates a forecasted stock market return of 12.58%. From this percentage, she deducts her forecasted 30-year U.S. Treasury risk-free rate of 4.30% to arrive at a forecasted MRP of 8.28%. It is worth pointing out that when witness Bulkley conducted her analysis of projected market returns in case U-21806 earlier in 2025, her expected market return was 12.04%, or 50 basis points less than in this case. This substantial swing in the stock market return over a short timeframe brings into

[119]Exhibit AG-50 includes DR AG-CE-0398 and attached Blue Chip Forecast of May 1, 2025.

question the wisdom of placing much reliance on this projected MRP methodology, and this is just one of the problems with this approach.

There are also other problems with the Company's approach in developing a projected MRP. As can be seen from an examination of pages 16 to 21 of Exhibit A-14 (AEB-1), many of the companies in the list of S&P 500 Index with dividend yields and long-term growth estimates are omitted. Approximately 125 companies or 25% of the named companies in the S&P 500 are not represented in the calculation of the12.58% stock market return. Also, many large technology companies with high growth prospects have a larger than normal weighting in the calculation of the 12.58% return due to their relatively large market capitalization.

Q. PLEASE EXPLAIN FURTHER THE SHORTCOMINGS WITH THE MARKET RISK PREMIUM DEVELOPED BY WITNESS BULKLEY?

A. Witness Bulkley is using an extremely short period of 3 to 5 years to measure stock market returns in determining the MRP. The projected MRP does not include a complete cycle of economic expansion and contraction, which is what occurs over the long-term. To adopt the Company's approach would be akin to only selecting the positive return years over the 98-year historical period of stock market returns I used and not the losses in the downturn years. Expectedly and incorrectly, we would derive a far higher overall return for the market and a far higher market risk premium, which is the flawed result achieved by witness Bulkley in the 12.58% market return and her forecasted MRP.

These concerns are also echoed by Dr. Roger Morin, a recognized expert on regulatory finance matters, who strongly supports the use of the longest possible period for calculating a market risk premium. On page 114 of his book "New Regulatory Finance" Dr. Morin states the following:

> Therefore, an historical risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earn a lower risk premium than they expect are offset by short-run periods during which investors earn a higher risk premium than they expect. Only over long time periods will investor return expectations and realizations converge. Clearly, the accuracy of the realized risk premium as an estimator of the prospective risk premium is enhanced by increasing the number of years used to estimate it…

Clearly, Ms. Bulkley's approach to calculating the projected market risk premiums is not academically or practically sound.

For the above reasons, witness Bulkley's development of the forecasted MRP used in her calculation of the CAPM and ECAPM cost of equity is seriously flawed and should be rejected.

Q PLEASE COMMENT ON MS. BULKLEY'S USE OF THE ECAPM METHOD.

The basic premise for the use of the ECAPM method is that the Beta factors published by Value Line when used in CAPM analysis do not accurately predict stock performance. However, as explained below, this argument is flawed.

Notwithstanding Ms. Bulkley's arguments, there is academic disagreement with the validity of the original studies that led to the use of ECAPM. First, the original study used

raw betas and not the adjusted Value Line betas, which I use, and other cost of capital experts normally rely upon. Second, the original studies relied upon short-term risk-free rates. Instead, cost of capital witnesses, including myself, who have been involved in the Company's rate cases use long-term risk-free rates in the CAPM model.

Dr. Morin points out this key difference on page 191 of his book "New Regulatory Finance" where he states that "…the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free rate version which has been tested."

The ECAPM produces a faulty cost of equity rate with a bias toward overstating and inflating the true cost of equity capital. The Commission should continue to disregard this alternative approach to the traditional CAPM method.

Q. HAVE OTHER REGULATORY COMMISSIONS WIDELY EMBRACED THE ECAPM METHODOLOGY FOR SETTING RETURN ON EQUITY RATES?

A. No. In response to previous discovery, the Company stated that ECAPM "… is supported by orders from regulatory bodies in Maryland, Mississippi and Alberta…" As a result of this claim, the Company was asked to provide the specific rate orders from these regulatory commissions.[120] This information was less than convincing.

[120] CECo responses to U-18424 AG-CE-206 and AG-CE-386.

Regarding the purported acceptance of the ECAPM in the State of Mississippi, the filing requirements of the Mississippi Commission require ECAPM filings. However, the extent to which Mississippi relies upon these estimates is unknown.

Regarding the Maryland commission, Company witness Maddipati pointed out on page 58 of his direct testimony in Case No. U-18424 that the Maryland Commission stated that they found the DCF and ECAPM "helpful" in Case 9326. However, in a more recent case involving PEPCO (case 9418) with an order issued on November 15, 2016, the result is different. As shown in the summary positions articulated in the order in this case, no party involved in the proceedings, other than the company, put forth an ECAPM ROE estimate. The Maryland commission basically adopted the Staff's position with no ECAPM estimate and rounded down the Staff's recommended ROE of 9.57% to 9.55%.

In this regard, the Maryland Commission stated on page 100 of the order the following. *"Our Decision today most closely aligns with Staff's recommendation of 9.57% although we do not expressly reach the same conclusion as Staff. We find that a slightly lower ROE of 9.55% is both adequate and appropriate for Pepco…"* Furthermore, in its decision in this case, the Maryland commission expressed no position on ECAPM. I am not aware of any more recent cases that show a change in the commission's view of the ECAPM methodology.

Utility Risk Premium Approach

Q. PLEASE EXPLAIN THE UTILITY RISK PREMIUM APPROACH OF ESTIMATING THE COST OF COMMON EQUITY.

A. In general, the cost of common equity for a peer group of utility companies can be estimated by (1) projecting the cost of debt for the peer group and adding to this cost (2) the average return differential of utility common stocks over utility bonds.

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-39 shows the components required to derive a cost of common equity capital for the peer companies on lines 3 and 4. The 5.56% on line 3 is the projected average rate for utility bonds rated "A". This rate reflects (a) the projected 30-year U.S. Treasury bond rate (discussed above in my CAPM section) of 4.40% plus (b) the average spread of 1.16% for 30-year "A" rated utility bonds issued in 2024 compared to U.S. Treasury bonds. Added to this result is the spread rate of 4.25% on line 4 of the exhibit, which is the historical rate of electric utility stock returns versus "A" rated debt yields from 1936 to the present. The total of the two rates equals the Risk Premium return rate of 9.81% on line 5 of the exhibit.

Q. DOES THE COMPANY PROVIDE A UTILITY RISK PREMIUM ANALYSIS?

A. No, not in the traditional sense of measuring achieved returns on utility stocks relative to an interest rate benchmark such as utility bonds. Instead, Company witness Bulkley uses an unorthodox approach she refers as Bond Yield Risk Premium (BYRP).

Q. PLEASE SUMMARIZE WITNESS BULKLEY'S TESTIMONY ON PAGES 30 THROUGH 33 STARTING UNDER THE HEADING "BYRP ANALYSIS" ON PAGE 30.

A. Witness Bulkley states in her testimony that she compared authorized ROEs from electric utility rate case decisions from 1980 to early 2025 to the 30-year U.S. bond yields. She ran a regression model with this data and claims to have found a strong relationship between these bond yields and authorized ROEs. Based on the results of the cases prepared using this approach, she concludes that the average risk premium over the 1980-2025 period is 6.15%. To this 6.15% developed risk premium, she adds an estimated rate of 4.41% for the 30-year U.S. bond yield for the projected test year to arrive at a 10.56% ROE rate for the projected test year under this unorthodox approach. The calculations are shown on page 22 of Exhibit A-14 (AEB-1).[121]

Q. WHAT IS YOUR ASSESSMENT OF THE BYRP APPROACH PRESENTED BY MS. BULKLEY?

A. There are three major flaws with Ms. Bulkley's Bond Plus Risk Premium methodology. First, it lacks any comparison of actual utility returns achieved from price appreciation and dividends to bond yields. It is the actual return on utility common equities that is the key and necessary measurement in any risk premium analysis. Using authorized ROEs as a

[121] Witness Bulkley's projected period results are 10.62% and 10.49% which averages to 10.56%. These two different rates utilize risk free rates for 30-year U.S. Treasury of 4.52% for the test year and 4.30% for the projected period through 2030.

substitute ignores investors' return expectations. Second, the analysis is biased because it covers a period when interest rates were declining from 12.1% in late 1980 to 4.2% in 2024.[122]

Third, this analysis assumes a direct relationship between declining interest rates and ROE decisions as happening almost instantaneously monthly. Regulators approach the serious business of establishing ROEs based on many factors including the concept of gradualism in reducing or increasing ROEs that are not in lock step with interest rate changes. This analysis has no validity as a tool to determine an appropriate ROE rate in rate case proceedings.

Q. HAVE REGULATORS IN OTHER JURISDICTIONS EMBRACED THE BOND YIELD RISK PREMIUM APPROACH?

A. No. The Attorney General asked the Company this question and the response was that "Ms. Bulkley does not keep an up-to-date database on the requested information," in other words, she could not provide evidence that any commission accepted this methodology.[123] An example of a jurisdiction rejecting the BYRP approach is the Utah commission decision in April 2025 in Docket 24-035-04 involving Rocky Mountain Power (RMP), a subsidiary of PacifiCorp. The Utah commission agreed with the arguments of the Office of Consumer Services (OCS) by stating that "As persuasively argued by OCS, and not

[122] Exhibit A-14 (AEB-1) pages 23 and 25
[123] See DR AG-CE-404

disputed by RMP, a fundamental component of the BYRP model is commission behavior (i.e., the authorized ROEs set by commissions over a historical period) and not investor behavior."[124] The Utah commission concluded that the RMP calculation of the BYRP ROE results to be unreliable. The Utah commission's position on this matter is on-point in recognizing that the "investor behavior component" is absent in the BYRP model approach. In contrast, investor behavior is a key component in the DCF, CAPM, and the Utility Risk Premium approaches I use in this case.

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE GRANTED DURING THE TWO YEARS ENDED JUNE 2025.

A. Exhibit AG-40 shows the ROEs granted by state regulatory commissions for U.S. electric utilities during the two years ending in June 2025. The majority of the 50 ROE decisions in the year ended June 2024 and the 46 decisions in the year ended June 2025 are at rates well below 9.90%, which is CECo's current authorized ROE.[125] As noted on page three of the exhibit, only ten decisions in the year ending June 2024 and fourteen decisions in year ended June 2025 were at rates of 9.90% or greater. These higher rates, which are summarized on page 3 of Exhibit AG-40 are primarily from regulatory commissions in California, Florida, and Michigan or pertain to small companies. ROEs in California have been at or above 10% reflecting the unique challenges for utilities in that state with

[124] Utah Commission order of April 2025 in Docket 24-035-04 at pages 25 and 26.
[125] The 2023 and 2024 decisions exclude Limited Issue Rider cases.

wildfires and earthquakes. ROEs in Florida reflect damage to utility property and financial losses from hurricanes, which is an on-going challenge for the utilities in this state. High ROEs in other jurisdictions tend to reflect smaller utilities or unique geographical challenges, such as in Alaska, as shown on page 3 of Exhibit AG-40.

For most of the other electric utilities that have business and financial risks comparable to Consumers Energy's operations, the ROE rates have averaged around 9.5% to 9.6% in the past two years. This evidence supports my calculations of an overall cost of equity of 9.73% and suggests that the Company's current ROE rate of 9.90% is excessive and "out of line" with comparable electric utilities and the true cost of equity capital. The Company's proposed ROE rate of 10.25% is even further removed from reality and clearly unsupportable. My recommended ROE rate of 9.80% in this rate case provides a bridge to ultimately reach the true cost of capital for the Company and is quite reasonable.

I highlight that the average ROE rate during the two years ended June 2025 for the utilities in my peer group is 9.57%. Exhibit AG-41 shows this information. This is another benchmark that shows the 9.80% ROE rate I have proposed is reasonable if not generous in comparison to peer companies.

Q. IN THIS RATE CASE, MR. BLECKMAN SPONSORS EXHIBITS A-30 (MRB-11) AND A-33 (MRB-14), WHICH INCLUDE A SELECT ANALYSIS OF UTILITIES WITH HIGH ROES AND A REPORT FROM REGULATORY RESEARCH

ASSOCIATES RANKING REGULATORY JURISDICTIONS IN THE UNITED STATES. WHAT IS YOUR ASSESSMENT?

A. Much of the information in Exhibit A-33 is incorrect, misleading, and does not accurately captures the assessment of the Michigan regulatory environment presented in Exhibit A-33 by RRA.

Regarding the information presented in Exhibit A-33, there are several special circumstances that need to be pointed out, which make the ROE rates presented unusual and not representative of the Company's regulatory position in Michigan. First, regarding Florida Power & Light, a 10.60% ROE was established by the Florida Commission in 2021 as part of a multi-year agreement covering the years 2022 to 2025. The ROE rate was recently increased to 10.80% due to a proviso related to higher U.S. Treasury bond rates. Under this agreement rate increases are capped, and any other relief would be dependent upon extraordinary circumstances.[126] In addition, this Company's service territory is impacted by hurricanes that can disrupt service for prolonged periods and potentially reduce revenues and profits. The ROE rate granted to Florida electric utilities is not applicable to Consumers Energy's electric business.

Second, Alabama Power, a Southern Company subsidiary, shows a 55% Common Equity ratio and a 10.90% ROE. The utility may potentially increase its rates each year but on a rolling two-year basis. However, the increases are limited to no more than 8% in a two-

[126] NextEra 2022 Form 10-K, page 9.

year period or 4% on average annually. The increases are authorized under the company's Rate RSE (established before 2016) which is determined by considering the level of earned returns on equity and the percentage of equity in the capital structure based on the company's Weighted Equity Cost Rate (WECR).[127]

In 2018, the Alabama Commission and the company agreed to a higher common equity ratio of 55% by 2025 from 47% in December 2018. The change to Rate RSE for Alabama Power was approved in May 2018 with no compensating rate increases and the company at that time consented to a nominal reduction in the WECR with no annual Rate RSE increases in 2019, 2020 and 2022. Rates were increased by 4.09% in 2021, but the Company also made refunds to customers via bill credits in the amount of $50 million for 2020, $181 million for 2021, and $62 million for 2022.[128] By virtue of this arrangement this company is forced to control capital spending and O&M expenses. This special rate and capital structure arrangement is not applicable to Consumers Energy for purposes of establishing an appropriate ROE rate in this rate case.

Third, the exhibit shows Georgia Power, another Southern Company subsidiary, with a 56% common equity ratio and an 10.50% authorized ROE. Until recently, Georgia Power was in a special situation involving significant expenditures and cost overruns for two nuclear power plants where (1) the original contractor declared bankruptcy; and (2) the Company has been forced to write-off approximately $2.0 billion of cost overruns in 2021

[127] Southern Company Form 2022 10-K starting at Page II-139 under "Rate RSE".
[128] Id.

and 2022; and (3) the Company has only recently completed the two nuclear units. The Georgia Commission has been very supportive of this company through this troubled time. The ROE and capital structure for Georgia Power are not applicable to Consumers Energy's electric business given the unusual circumstances.

Fourth, regarding WEC, which owns gas and electric utilities in Wisconsin and other jurisdictions, the 10.15% ROE shown in the exhibit is applicable to less than 2% of its revenues in 2024 pertaining to a very small utility in Michigan's upper peninsula. For 2025, the Michigan Commission recently reduced the ROE for this small utility to 9.85% and the common equity ratio to 50% effective January 1, 2025.[129] Recent decisions from the Wisconsin Commission in general rate cases have granted ROEs of 9.80%.[130]

Fifth, for UGI, electric rate cases from 2020 through 2024 for this utility have been settled without published rate metrics. Moreover, UGI's electric operations are for service to approximately 63,000 customers in parts of Luzerne and Wyoming counties in Pennsylvania.[131] Therefore, the information shown in this exhibit is stale and inapplicable.

In summary, Mr. Bleckman's attempt to inflate his ROE recommendation by pointing to select and inapplicable ROE rates granted to other utilities fails to provide convincing evidence and should be rejected by the Commission.

[129] WEC 2024 Form 10-K, page 20 for additional information pertaining to Upper Michigan Energy Resources Corporation (UMERC).
[130] Regulatory Research Associates 2024 Report.
[131] See the 2024 UGI Form 10-K, page 14.

Regarding Exhibit A-33, the RRA report categorized the Michigan regulatory environment at Average-1, which is the high end of average and just below the above average ranking. RRA also assigns Average-2 and Average-3 rankings, which are below the Average-1 ranking. The Average-1 ranking assigned to the Michigan regulatory environment is still very strong and when combined with the S&P ranking of the Michigan regulatory jurisdiction as "Most Credit Supportive," on page 8 of Exhibit A-40, shows that the Company benefits from a very supportive regulatory environment.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE BELOW 9.90% IN THIS CASE WILL LEAD TO IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?

A. No. From time to time in general rate case proceedings, certain applicants, including the Company, have raised arguments that they should receive higher ROEs to ensure the financial soundness of the business and to maintain its strong ability to attract capital in addition to being compensated for risk. However, those concerns are not supported by the evidence. Exhibit AG-40 shows several electric utilities that have accessed the capital markets at competitive interest rates since receiving ROEs near or below the average rate of 9.50%.

Similarly, there is no evidence that equity investors have abandoned utilities that have been granted ROEs near or below the industry average. On the contrary, stock investors

continue to migrate to utility stocks, recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-43 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past few years reflecting ROEs as low as 8.63%. Yet this group of companies has an average Market to Book common equity value ratio of approximately 2.0 times.

A market to book value greater than 1.0 shows that investors are attracted to the return (ROE) earned by utilities on their book value. A higher market to book ratio indicates that the utility is earning a higher return on book value than other utilities. It also indicates that the utility is earning a return on book value that is higher than the investor expects for that type of investment and is willing to pay a higher market price for the stock than book value.

This information is provided to dispel the myth that the Company must receive a high ROE above the industry average, or it will face dire consequences in the financial markets.

The fact that the Company needs to raise capital because of a large capital investment program to upgrade its infrastructure and for other purposes is not unique to Consumers Energy. Most electric utilities face the same issues and are able to raise capital with ROEs at or near the 9.5% average rate. Therefore, this issue is another "red herring".

WITNESS BULKLEY RAISES THE SUBJECT OF THE VIX AS A MEASURE OF VOLATILITY AND RISK ON PAGE 17 OF HER TESTIMONY AND SHOWS A GRAPH (FIGURE 4) REFLECTING A VIX RATE OF 52.3 IN APRIL 2025. WHAT IS YOUR ASSESSMENT?

A. Ms. Bulkley claims that the higher volatility represented by the VIX reflects a need for higher returns in the market. The 52.3 VIX level she shows in Figure 4 reflects a period of temporary market turmoil when the "Trump tariffs" were introduced. Since April 2025, greater clarity in the markets has taken hold and the VIX fell to 14.79 by August 19, 2025, which is near the lowest level so far this year. The relevance of the VIX is discussed further below.

Q. ON OCCASION IN PAST RATE CASES, THE COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO AUTHORIZE A HIGHER ROE RATE. SHOULD STOCK MARKET VOLATILITY OR THE VIX INDEX BE A CONCERN IN ESTABLISHING A FAIR ROE RATE FOR THE COMPANY?

A. No. The stock market has historically been very volatile. Currently, this is measured by the VIX, which portrays volatility over the next 30 days. In some periods, stock prices move up and down more dramatically than at other times. The key factor is that the VIX is telling us something about risk in the market over the next 30 days and not the risk several months in the future. In setting ROE rates for utilities, the Commission's focus is the long-term financial health of the utility not the short-term gyrations of the stock market.

As a supporting point, in Exhibit AG-51, I have included a Value Line Funds article written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not risk. For example, he points out that volatility in 2017 was low by historical standards and it was near normal levels in 2018. Mr. Appel goes on to say later in this article that

"…volatility is only risk if you act during down times, that is, only if you sell a stock." This principle still applies to events today.

Additionally, I will submit that those who invest money in equity portfolios over longer periods of time and particularly in utility stocks have an aversion to market volatility and the VIX. In fact, utility stocks are a safe-haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market. This is reflected in the average Beta value of 0.76 of the utility peer group used in the CAPM discussed earlier, in contrast with the general stock market value of 1.0. The recent stock market volatility in April 2025 due to the imposition of trade tariffs is an example where utility stocks have outperformed the general stock market as a safer heaven for investment.[132] Therefore, the Commission should not give any weight to arguments that the Company's ROE should reflect investors' concerns with stock market volatility.

Q. HAS THE MARKET FOR NEW LONG-TERM DEBT BEEN RECEPTIVE TO NEW UTILITY DEBT ISSUES IN 2023 AND 2024?

A. Yes. As shown on Exhibit A-28 (MRB-9), the market for new utility debt issues has been very robust with over 400 new issues completed in 2023 and 2024. Also, as can be seen from Exhibit AG-40, many utility companies issued new debt shortly after receiving a rate order with ROEs below 9.50%.

[132] From the end of 2024 and through April 15, 2024, CMS Energy Stock was up 9.1% while the S&P 500 Index was down 8.2%.

So far in 2025, Consumers Energy has issued $1.125 billion of new long-term debt at rates of 4.5% (5.5 years to maturity) and 5.05% (10 years to maturity). Also, Consumers Energy issued $700 million of long-term debt in July 2024 at an interest rate of 4.7% and a 5-year term. Additionally, in January of 2024, Consumers Energy issued $600 million of new 10-year debt at an interest rate of 4.6%. CMS Energy has also come to market and issued $1.0 billion of new 30-year debt at a rate of 6.5%. In Exhibit AG-40, I show several utility companies who came to market not long after a rate case decision and issued significant quantities of new long-term debt.

This information demonstrates that the debt markets are receptive to utility companies' capital raising activities.

Q. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE RETURN ON EQUITY RATE THAT THE COMMISSION SHOULD APPROVE IN THIS RATE CASE.

A. In Exhibit AG-36, I summarized the cost of equity rates from the three methods I discussed above. The range of returns for the industry peer group is from 9.57% at the low-end, using the DCF approach and 9.98% at the high end using the CAPM approach.

As explained earlier in my testimony, I give 50% weight to the DCF method as a more reliable approach to estimating the cost of equity for a utility, which from my analysis is a rate of 9.57%. In this regard, on line 4 of Exhibit AG-36, I have calculated a weighted return on equity from the three methodologies using a 50% weight for DCF and 25% for

each of the other two methods. The result is a weighted average cost of common equity of 9.73%. I rounded this rate up to a recommended ROE rate of 9.80% for Consumers Energy's electric business. With the recent reduction in interest rates by the Federal Reserve Bank and expected additional reductions in coming months, the 9.80% proposed ROE rate is reasonable if not very generous to the Company. Therefore, there is no need to further increase the ROE rate above 9.80% for further interest rate risk and I urge the Commission to adopt this proposed rate.

Q. IF THE COMMISSION APPROVES A 9.90% COST OF COMMON EQUITY IN THIS CASE, AS IT DID IN CASE NO. U-21585, WHAT IS THE ADDITIONAL COST TO CUSTOMERS COMPARED TO AN ROE OF 9.80%.

A. If the Commission were to approve a 9.90% ROE in this case versus a 9.80% ROE, the additional cost to customers is approximately $8.9 million annually. There is absolutely no need to burden customers with this additional cost.

I recommend that the Commission take note of the evidence and arguments I have presented in my testimony and grant the Company a ROE rate of no more than 9.80%.

Q. AT THE PREHEARING FOR THIS RATE CASE, THE ADMINISTRATIVE LAW JUDGE (ALJ) REQUESTED THAT PARTIES TO THIS CASE SUBMITTING TESTIMONY ON THE AUTHORIZED ROE PROVIDE INFORMATION ON (A) THE REPORTED FORECASTED RETURN ON EQUITY FOR THE UNITED STATES STOCK MARKET AND (B) THE REPORTED AVERAGE ROE

AUTHORIZED FOR REGULATED UTILITIES FOR THE LAST TWO OR MORE YEARS. WHAT INFORMATION HAVE YOU INCLUDED IN YOUR TESTIMONY AND WHAT IS YOUR ASSESSMENT OF THE REQUESTED INFORMATION?

A. Regarding the ROE rates authorized for regulated utilities, as I have done in prior rate cases, I included Exhibit AG-40 with my testimony, showing the ROEs for electric utilities approved by state commissions in Michigan and other states during the 24 months ended June 2025. As discussed in more detail above, the average authorized ROE rate was 9.67% during the 12 months ended June 2024 and 9.76% for the 12 months ended June 2025. The source of this information is a quarterly survey performed by Regulatory Research Associates, which is an affiliate of S&P Global. Exhibit AG-52 Confidential includes a copy of the latest published report with supporting detail available as of the date of this testimony.[133]

Regarding the request for the reported forecasted return on equity for the United States stock market, the task is more challenging. There is no known publication or service, that I am aware of, that gathers and reports this information. This is not typically information that investors focus on when making investment decisions for non-regulated companies. There is also the question of what index truly represents the U.S. stock market. The S&P 500 Index is a commonly monitored index along with the Dow Jones Industrial Average

[133] Exhibit AG-40 with individual utility approved ROEs is an accumulation of prior period reports published by RRA.

Index, the NASDAQ, and the Russell 2000 Index among others. Each of these indexes has their own composition of companies. The S&P 500 index includes the largest publicly traded companies listed in the United States. The Down Jones Index includes 30 large, publicly traded blue-chip companies, from various sectors of the U.S. economy. The NASDAQ includes domestic and international companies listed on the Nasdaq Stock Market that are primarily technology-focused. The Russel 2000 Index consists of small publicly traded U.S. stocks. Therefore, there is no easy answer as to what represents the U.S. stock market and even more difficult what the average forecasted ROE rate is for the companies in these indexes.

To be responsive to the request, I calculated what the historical stock market return has been of the companies in the S&P Index and the predecessor index of the largest U.S. stock market companies for the 99 years from 1926 to 2024. The average annual return for the largest companies in the U.S. stock market over this long period of time was 12.3%.[134] I also calculated the return that investors investing in the S&P 500 Index could potentially expect to earn based on earnings growth forecasts and the stocks' dividend yield of most of the companies in the index as of a point in time.

The approach here is similar to the DCF model used to arrive at the ROE return for the utility peer group I discussed above. The result is an expected annual return of 12% based

[134] Exhibit AG-45.

on the current dividend yield and the earnings forecasted for companies in the S&P Index for the next three to five years.[135]

Interestingly, as of this point in time the forecasted return of the S&P 500 index of companies of 12% is similar to the historical return of 12.3%. This is merely a coincidence given that earnings forecasts for companies in the index change from month to month as companies change their forecasts. Therefore, I would caution against using or relying on any forecasts of stock market returns as a benchmark to guide or set the authorized ROE for electric utilities and the Company in particular in this rate case.

As I discussed above, although the long-term historical return of the S&P 500 Index can be used in determining the Market Risk Premium for the CAPM calculation, forecasted returns are speculative and uncertain given the short-term nature of those forecasts and the fact that they do not reflect both the up cycles and down cycles of the stock market.

Also as discussed above, an appropriate ROE for Consumer Energy is 9.80%, applying commonly used methodologies and considering investor expectations and the guiding principles of *Bluefield* and *Hope*.

VIII. Operations and Maintenance Expenses

[135] Exhibit AG-46 provides this calculation. Due to negative earnings and other unusual circumstances, 35 companies from the S&P Index were removed and the calculations are based on 465 companies.

Q. WHAT ARE YOUR FINDINGS IN ANALYZING THE COMPANY'S LEVEL OF O&M EXPENSES INCLUDED IN THIS RATE CASE?

A. In Exhibit A-13 (PDD-42), Schedule C-5.1, the Company shows forecasted O&M expenses of $805.0 million for the projected test year, which is an increase of $141.2 million from the 2024 historical year. The increase primarily reflects substantial expense increases in three areas (a) $54.4 million in the Electric Division including service restoration costs, (b) $76.5 million for higher Forestry management expenses, and (c) $33.0 million related to higher Information Technology expenses. These three areas reflect a total increase in expenses of $163.9 million which is offset primarily by lower power generation expenses and lower pension and OPEB expenses.

Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE O&M EXPENSES SHOULD BE REDUCED?

A. Yes. I analyzed O&M expenses by major department or area, and I have identified more appropriate and reasonable expense levels that the Commission should consider. In my testimony below, I will recommend that forecasted O&M expenses should be reduced by $137.9 million. Exhibit AG-53 shows a summary of my proposed O&M expense adjustments.

A. Inflationary Adjustments to O&M Expenses

Q. HAVE YOU MADE ANY REDUCTIONS TO THE INFLATION INCREASE ADJUSTMENTS TO O&M EXPENSES PROPOSED BY THE COMPANY IN THIS RATE CASE?

A. No. Where in prior rate cases, the Company proposed to use a different forecasted rate for annual employee salary/merit increases, in this rate case, it proposed to use a rate of increase equal to the CPI forecasted inflation rate.

I agree with the Company's use of CPI increases of 2.1% for 2025, and 2.4% for 2026 and 2027.

B. Electric Division

Q. WHAT ADJUSTMENTS DID THE COMPANY MAKE TO ITS ELECTRIC DIVISION EXPENSES FROM THE HISTORICAL TEST YEAR TO THE PROJECTED TEST YEAR?

A. As shown on line 55 of Exhibit A-124 (MPK-14), Electric Division O&M expenses were $246.6 million in 2024 and the Company is forecasting expenses of $301.0 million for the projected test year. In this exhibit, the Company also shows the historical expense by sub-program for the five years from 2020 to 2024 and the average expense amount during this period. Excluding Service Restoration Costs, the Company total forecasted Electric Division O&M expenses increase from $90.5 million in 2024 to $135.8 million in the projected test year, which is a 50% increase. Much of these requested increases are for additional inspections and maintenance of lines and facilities that seemingly require the hiring of additional employees and/or contractors, emanating from the Company's Reliability Roadmap.

In his direct testimony, Mr. Kelly explains the projected test year expenses in broad statements with very few specifics. His direct testimony lacks a robust discussion of new work activities, increases in work units to be completed, or specific dollar amounts of expenses that are increasing from either 2024 or from the five-year average amount. Although on occasion he provides forecasted work units and components of programs, there is no comparison to historical quantities or activities to justify increases in costs. The

result is that there is very little quantifiable support for some of the increases in expenses at the program or sub-program level.

In my testimony below, I will address the increases in expense in some of the programs listed in Exhibit A-124 (MPK-14), including the Service Restoration expense forecasted by the Company for the projected test year, which is sponsored by Company witness Andrew Snider. Exhibit AG-54 summarizes the adjustments.

1. Service Restoration Expense

Q. THE COMPANY PROPOSES SERVICE RESTORATION O&M EXPENSES OF $165.2 MILLION IN THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS LEVEL OF EXPENSE?

A. No. On line 23 of Exhibit A-124 (MPK-14), the Company shows service restoration expense of $156,098,000 for 2024, $137,666,000 for the 5-year average, and $165,215,000 for the projected test year ending April 2027. In his direct testimony, Company witness Andrew Snider adopts a new methodology of building up service restoration expenses for the bridge period taking 8 months of that expense and adding for months of the built up 2027 service restoration expense by using the actual expense from 2024 as a base. Page 20 of his testimony describes this new method.

Mr. Snider new approach veers from the long-standing practice of using an average of the last five years of restoration expense to set the forecasted amount for the projected test

year. The five-year approach normalized and evened out peaks and valleys in the annual expense to avoid large fluctuations in the projected test year expense instead of relying solely on the expense incurred in the most recent year, as Mr. Snider has done under his new approach. Mr. Snider's approach is flawed and should be rejected.

Q. WHAT IS THE SERVICE RESTORATION EXPENSE AMOUNT THAT YOU PROPOSE FOR THE PROJECTED TEST YEAR?

A. Using the actual service restoration expenses for the five years from 2020 to 2024, I calculated the average expense amount of $137,666,000. I adjusted this amount by the inflation rates for 2025 to the end of the projected test year and arrived at the adjusted forecasted expense of $144,572,000. This amount is $20,643,000 less than the $165,213,000 forecasted by the Company. Exhibit AG-55 shows the calculation. I recommend the Commission adopt the traditional calculation I have presented above and remove $20,643,000 from the Company's forecasted O&M expense for the projected test year.

Q. IN HIS DIRECT TESTIMONY, MR. SNIDER PROPOSES A SERVICE RESTORATION RESILIENCY FUND AND AN EXTRAORDINARY STORM ACCOUNTING PROCEDURE. WHAT IS YOUR ASSESSMENT?

A. Both the Resiliency Fund and the Extraordinary Storm Accounting (ESA) are complex proposals that require more research and study to assess how they would work in practice and their implication on cost recovery. They also are designed to reduce financial risk for

the Company, which has considerable implications for the return on equity rate. A major reduction in risk and the likelihood of increased cost recovery of historical storm restoration costs would need to be reflected in a significant decrease in the approved ROE rate for the Company.

The few examples that the Company has referenced in Mr. Snider testimony are not compelling. No evidence has been presented of how well or poorly those mechanisms have worked for customers and the companies involved. The examples are primarily for smaller utilities than the Company that have less financial flexibility to handle peaks and valleys in annual restoration costs.

It is premature at this time to adopt the Company's proposals and I recommend that the Commission not do so in this rate case. If the Commission finds merit in exploring the Company's proposals and perhaps other proposals, I recommend that it open a new generic docket to review various proposals that could be applied not only to the Company but also to other electric utilities in Michigan. All electric utilities face the issue of volatility in service restoration costs, and it is desirable to have a consistent approach to ratemaking on this type of expense across all utilities under the Commission's jurisdiction.

2. Staking and Locating

Q. THE COMPANY PROPOSES $13.9 MILLION FOR ITS STAKING AND LOCATING PROGRAM COMPARED TO $6.1 MILLION IN 2024. WHAT IS YOUR ASSESSMENT?

A. There are two main issues with the Company's proposed expense for the projected test year. First, the Company has overstated the number of staking and locating requests forecasted for the projected test year. On page 150 of his direct testimony, Mr. Kelly shows the buildup in service requests using a 7% annual rate of growth. This rate of growth is not reflective of the staking and locating requests that the Company has received annually from 2021 to 2024. Using the Company's own numbers, the actual rate of growth has been 2%. At this rate of growth, the number of staking and locating requests forecasted for the projected test year are 453,640. To this number, I applied the contractor's average cost rate for the year to arrive at a forecasted cost of $12,348,000. After adding the MISS Dig annual dues and fees of $734,000, the total forecasted staking and locating expense is $13,052,000. This amount is $866,000 lower than the $13,948,000 forecasted by the Company. Exhibit AG-56 shows the calculations. I recommend that the Commission remove the $866,000 from the Company's forecasted O&M expense for the projected test year.

Second, beginning on page 145, Mr. Kelly's testimony states that the Company has decided to change its staking and locating program to a dedicated contractor approach instead of a shared contractor model throughout its service territory. Until recently, the Company had moved to a dedicated contractor for only Oakland and Kent counties because of performance problems experienced with a previous contractor. The move to a dedicated contractor model increases costs dramatically from $6.1 million in 2024 to $13.9 million in the projected test year. No evidence has been presented by the Company in this case

that significant problems existed in the rest of the Company's service area that could not be resolved otherwise and require a costly dedicated contract approach. Any improvement in performance in Oakland County does not apply to other counties if no significant performance problems exist in those counties.

I find the Company's move to an expensive dedicated model unjustified and the increase in expense imprudent. Based on the cost information provided by the Company in response to discovery,[136] the increase in expense of expanding the dedicated model to other areas of the state is $5,872,000. Exhibit AG-56 shows the calculation. I recommend that the Commission remove the $5,872.000 from the Company's forecasted O&M expense for the projected test year.

In total, for Staking and Locating, I recommend that the Commission remove $6,738,000 for the projected test year O&M expense.

3. HVD Lines Demand

Q. O&M EXPENSE FOR HVD LINES DEMAND INCREASED FROM $898,000 IN 2024 TO $2,979,000 IN THE PROJECTED TEST YEAR. PLEASE EXPLAIN WHAT LEVEL OF EXPENSE IS APPROPRIATE FOR THIS EXPENSE ITEM.

A. On line 9 of Exhibit A-124 (MKP-14), witness Kelly shows HVD Lines Demand expense increasing from $898,000 in 2024 to $2,237,000 in 2025 and then further increasing it to

[136] Exhibit AG-56 includes DR AG-CE-0445.

$2,979,000 in the projected test year. As a point of reference, during the five years from 2020 to 2024, this expense never exceeded $1.1 million annually.

On pages 139 and 140 of his direct testimony Mr. Kelly states that the Company has increased the use of infrared cameras to spot anomalies in HVD lines and the expense level supports preventative maintenance. It is worth pointing out that in Case No. U-21585 filed a year ago no large increase in expense was proposed or no mention was made regarding the need for additional preventive maintenance. In discovery, the Attorney General asked the Company to provide the actual year to date O&M expense for 2025.[137]

The O&M expense for the first eight months of 2025 were only $453,130, reflecting an annualized expense level of $680,000. This amount is significantly below the Company's 2025 projection of $2.2 million. It is apparent from this recent actual level of spending that the forecasted expense amount for the projected test year is overstated. Therefore, I recommend that the projected test year spending level should be set at $1,086,000, which is the highest expense incurred in the past five years. This amount is $1,893,000 lower than the $2,979,000 forecasted by the Company. I recommend that the Commission remove the $1,893,000 expense difference from the Company's projected test year O&M expense.

[137] DR AG-CE-510.

4. Service Calls

Q. LINE 17 OF EXHIBIT A-124 (MPK-14) SHOWS O&M EXPENSE FOR SERVICE CALLS INCREASING FROM $4,194,000 IN 2024 TO $5,699,000 IN THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS INCREASE?

A. No. On page 160 of his testimony, Mr. Kelly attributes the 36% increase in expense to higher labor costs (16% more than in the five-year average) and a projected increase in hours worked (17% more). The work performed in this category is related in part to service disconnections, reconnections, and new service line connections, among other customer requests. Since the work involved is performed by union employees, the labor cost per hour can be reasonably determined. As such, I agree with Mr. Kelly's 16% increase due to labor costs.

However, the increase in workload of 17% is not supported in the testimony of Mr. Kelly. In discovery, the Attorney General asked the Company to justify the cost increases. The discovery response shows actual Service Call hours worked in 2022 of 27,185, which decline slightly in 2023 and again in 2024.[138] This data does not support the 17% increase in workload in the past three years and no other evidence has been provided about large increases in future years.

[138] DR AG-CE-0514

Accordingly, the Company's historic five-year average expense of $4,225,000 is an appropriate base amount in this case after adjusting it for the labor cost increase of 16% or $676,000. This adjustment results in an expense amount of $4,901,000 for the projected test year. This amount is $798,000 lower than the Company's forecast of $5,699,000. I recommend that the Commission reduce the Company's projected O&M by $798,000.

5. Lines Reliability LVD and HVD

Q. EXHIBIT A-124 (MPK-14), LINE 4, SHOWS LVD LINES RELIABILITY O&M EXPENSE INCREASING FROM $0.6 MILLION IN 2024 TO $8.0 MILLION IN THE PROJECTED TEST YEAR. WHAT IS YOUR ASSESSMENT?

A. The dramatic escalation in O&M expense for LVD Lines Reliability is excessive and should be moderated. As shown on line 4 Exhibit 124, the largest expense amount incurred in this area in the last five years was $1.1 million in 2022. Although in response to discovery in the last rate case (U-21585), the Company stated that it had not been following IEEE recommendations and best practices for inspection and maintenance,[139] it is not reasonable for the Company to undertake an 8-fold escalation in expense in less than two years to reverse past poor practices.

In Case U-21585, the Company proposed a $30.2 million expense level for this expense item for the projected test year. However, in this rate case, the Company has scaled back

[139] U-21585 Exhibit AG-1.37 includes U-21585 DR AG-CE-0430.

its request to $8.0 million starting in 2025. The Attorney General asked the Company to provide the actual expense during the first eight months of 2025. The Company's response shows that $607,360 was spent in the first eight months of 2025, or an annualized level of $911,000. [140] Adding inflation adjustments to this amount brings the expense for the projected test year to $940,000, which is less that one-eighth the Company's forecasted amount of $8.0 million for the projected test year. Therefore, I recommend that the Commission remove the difference of $7,060,000 from the O&M expense forecasted for the projected test year.

Q. EXHIBIT A-124 (MPK-14), ON LINE 5, SHOWS HVD LINES RELIABILITY O&M EXPENSE INCREASING FROM $109,000 in 2024 TO $891,000 IN THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE O&M EXPENSE INCREASE?

A. No. In discovery, the Attorney General asked the Company about the increase in O&M expense for HVD Lines Reliability. In the response, the Company stated that they re-evaluated their position and that the five-year average expense amount of $214,000 is an adequate spending level.[141] This amount is $677,000 below the $891,000 forecasted by the Company.

[140] DR-AG-CE-0507 with attachment.
[141] DR-AG-CE-0508.

Therefore, I recommend that the Commission remove that amount from the Company's forecasted O&M expense for the projected test year.

Q ON LINE 49 OF EXHIBIT A-124 (MPK-14), THE COMPANY FORECASTED THAT THE ELECTRIC DISTRIBUTION – LVD O&M EXPENSE WILL INCREASE FROM $7.3 MILLION IN 2024 TO $11.0 MILLION IN 2025 AND TO $11.8 MILLION IN THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE 60% INCREASE IN EXPENSE?

A. No. Mr. Kelly discusses this expense item on pages 179 to 181 of his testimony. Expenses in this area cover salaries and other expenses for the LVD engineering organization which includes LVD planning, design, joint pole rental expenses, and the Grid Automation teams. Over the past five years, expenses in this area have ranged from $5.8 million to $8.6 million with the most recent year (2024) at $7.3 million. On page 181 of his testimony, Mr. Kelly attributes the large increase to additional "…projects being identified as part of the Reliability Roadmap."

Exhibit A-124 (MPK-14) projects $11.0 million of expenses for 2025. In discovery, the Attorney General asked the Company to provide actual 2025 expense information for the first eight months of 2025. The Company's response shows the total expense for the first eight months of 2025 at $3.243 million, which is an annualized expense level of $4,865,000 and well below the actual 2024 level of $7,254,000.[142] This $4,865,000

[142] DR AG-CE 0517.

annualized 2025 expense is also well below the Company's projected test year expense. Moreover, the tasks performed in this area have been on-going for some time and therefore the rationale for a large ramp-up of expenses is not supported by Mr. Kelly's testimony.

Therefore, I recommend that the Commission should set the expense at the 2024 level of $7,254,000 and reduce O&M expense for the projected test year by $4,519,000 from the $11,773,000 forecasted by the Company.

6. Line Clearing Expense

Q. IN HER DIRECT TESTIMONY, WITNESS SARA STEWART PROPOSES THE ESTABLISHMENT OF A REGULATORY ASSET TO DEFER TREE CLEARING COSTS ABOVE A STATED THRESHOLD. DO YOU AGREE WITH HER PROPOSAL?

A. No. The Company has chosen a baseline of $164.5 million as the threshold above which tree or line clearing expenses would be deferred and charged to the regulatory asset account for later financing through securitization. Although I agree in principle with the proposal to defer the line or tree clearing costs above a reasonable threshold, the Company's proposed baseline is too high and reduces the opportunity to defer and securitize a higher amount of tree clearing costs.

The genesis of the deferral proposal is the Company shift from a seven-year tree clearing cycle to a five-year cycle. Although the Company plans to officially start the five-year

cycle in 2026 subsequent to a Commission order in this case, it has already started to accelerate spending on tree trimming in 2025 to $125.4 million from the $110.2 million spent in 2024.[143] Figure 12 on page 35 of Ms. Stewart's direct testimony also shows that the number of miles scheduled to be cleared in 2025 are increasing to 6,108 from 5,400 miles in 2024. Therefore, a strong case can be made that 2024 is a reasonable baseline of tree clearing expenses and expenses above that amount beginning with 2025 or 2026 and future years should be charged to the regulatory asset for future securitization.

I recommend that the Commission approved the 2024 line clearing expense amount of $110,225,000 as the baseline amount and direct the Company to defer all expenses above that amount beginning in 2026 to the regulatory asset. For the projected test year, the Company forecasted $186,684,000 in O&M expense for line clearing (Forestry), as shown in Exhibit A-170 and Exhibit A-13, Schedule C-5.1. Based on this amount and the baseline of $110,225,000, the difference of $76,459,000 should be removed from O&M expense in this rate case and included the regulatory asset account. Later in my testimony, I will discuss the appropriate return to be applied to the regulatory asset balance.

Therefore, I recommend that the Commission approve both the $110,225,000 baseline and the transfer of $76,459,000 from O&M expense to the regulatory asset account for the projected test year.

[143] Exhibit A-170 (SES-1).

C. IT O&M Expense

Q. WHAT ADJUSTMENTS DO YOU RECOMMEND TO THE PROJECTED TEST YEAR O&M EXPENSE FOR IT PROJECTS?

A. As discussed above in the Capital Expenditures section of my testimony under IT projects, I recommend that the Commission approve the removal of $18,314,000 of O&M expense from the Company's forecasted projected test year expense.

D. Incentive Compensation Expense

Through the testimony of witnesses Amy Conrad and Ashley Meschke, the Company proposes to recover in rates approximately $2.2 million of short-term incentive compensation.[144] These dollars are related only to the operational metrics utilized by the Company and the costs related to the Company's financial metric goals were excluded by the Company in this case.

In the following pages of my testimony, I will analyze the Company proposal to include in rates the cost of incentive compensation and the alleged benefits to customers provided by Ms. Meschke in her testimony related to the operational metrics. Over the past few years, the Company has made several changes to the incentive plan that have made it easier for the Company to payout incentive compensation. For example, the operating performance measures that drive the short-term incentive payouts under the plan were

[144] Exhibit A-73 (AMC-3).

revamped. Beginning in 2022, the ability to trigger a payout has been modified to make it much easier for employees to receive incentive compensation payments. I will discuss these changes in more detail later in my testimony.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S SHORT-TERM INCENTIVE COMPENSATION PLAN.

A. The Company has a short-term incentive compensation plan for officers and a slightly different plan for non-officer employees. The Company refers to each of these plans as the Employee Incentive Compensation Plan (EICP).

The major components of the EICP for non-officer employees are shown in Exhibit A-71 (AMC-1). Fifty percent (50%) of the target award in 2024 was based on achieving 6 performance measures related to employee safety, customer experience, electric reliability, affordability/waste elimination, as well as employee satisfaction surveys and methane emission reduction. The remaining 50% is based on the financial results of CMS Energy. This 50/50 combination of operating and financial measures started in 2012.

In 2010 and 2011, the calculation of the non-officer EICP was based solely on achieving operating performance measures. The requirement to achieve 100% payout of target was also stricter with accomplishment of 9 measures out of 11 needed. The Company then adjusted this percentage based on the percent payout of the officers' EICP. Over the last seven years, non-officer employees have received incentive payouts as a percentage of target of 123% in 2018, 111% in 2019, 139% in 2020, and 77% in 2021 160% in 2022

140% in 2023 and 136% in 2024.[145] The only year in the past fourteen years where a bonus payout was not made to non-officer employees was in 2011 when only 6 of the 11 operating measures were achieved. These consistent payouts indicate that incentive compensation is not at-risk compensation based on achieving superior performance but it simply supplements base pay.

For the officers' EICP, the target payout has been based almost entirely on earnings per share and operating cash flow. However, more recently, 70% of the target payout is from achieving the CMS Energy earnings per share goal and 30% from achieving similar operating performance measures of non-officer employees.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF BOTH THE OFFICER AND NON-OFFICER EICP?

A. Generally, the Company's short-term incentive plans are too heavily weighted toward financial measures that mostly benefit shareholders and not customers.

For the 2024 plan cycle, half of the non-officer employee EICP payouts and 70% of the Officer EICP payouts were dependent upon the financial metrics. As such, the officer group that sets the direction of the Company is still far too focused on financial results. Customers do not directly benefit from shareholders achieving a higher return on their investment. Although the Company has argued in the past that happy investors will be

[145] See U-21806 DR AG-CE – 0672 with attachments and U-21490 DR AG-CE-165 with attachment.

more attracted to the Company's debt and common stock issues and therefore provide a lower cost of capital, it has not offered direct proof to support this argument. The argument is particularly hollow since the Company has not issued any significant common stock in more than five years. Later in my testimony, I will discuss in more detail the customer benefits put forth by Ms. Meschke.

Q. DO YOU SEE ANY OTHER PROBLEMS WITH THE MEASURES INCLUDED IN THE EICP?

A. Yes. In the past, the Company had to achieve at least a minimum number of operating metrics to trigger an incentive payout. Although, the number of operating metrics to be achieved was relatively low to demonstrate exceptional performance even that minimal requirement has now been dropped. Therefore, even mediocre performance will be rewarded if only a single metric is achieved. This is a very generous incentive plan that is not directly connected with achieving superior customer benefits before making threshold incentive payouts.

Additionally, the fact that the performance measures use CMS Energy financial information and comingle electric and gas business measures is a concern. Although the Company is a combined gas and electric utility and makes up 95% of CMS Energy, appropriate cost segregation is required to avoid having gas customers subsidize other businesses, particularly non-utility operations.

Lastly, the Company has indicated that it continues to pay salary increases each year with increases well above the rate of inflation over the last five years.[146]

Q. PLEASE BRIEFLY SUMMARIZE AND PROVIDE YOUR ASSESSMENT OF THE CUSTOMER BENEFITS PRESENTED BY THE COMPANY TO JUSTIFY RECOVERY OF INCENTIVE COMPENSATION COSTS.

A. In her testimony, Ms. Meschke attempts to quantify certain benefits related to three of the operating performance measures that are part of the EICP. In Exhibit A-157 (AEM-2), Ms. Meschke shows the number of Safety Incidents, which were 107 in 2022 and 124 in 2024. The actual trend of safety incidents has been upwards. To calculate "potential" cost savings, the Company assumed it would be able to reduce the number of safety incidents to 83 in 2025 and based the calculation on that lower number. However, this is wishful thinking and not actual cost savings achieved. With higher safety incidents in 2024 than in any other year shown on this exhibit, costs have increased and not decreased. The exhibit also shows that the Company's Workers Compensation and other related costs have been erratic from 2021 to 2024 with no consistent downward trends to create cost savings. Clearly, these results do not show superior performance or an improving trend.

In Exhibit A-158 (AEM-3), Ms. Meschke shows the Company's SAIDI Index results as a measure of Electric Reliability. Her exhibit does show that the annual SAIDI value for the

[146] Discovery Response AG-CE-533 shows increases for the officer group of 4.24% and for non-officers of 3.1%.

Company was 155 in 2024 which is lower than the average indicated for the prior four years of 195 or 8 minutes lower per year from 2020 to 2024. Based on this information, she estimates savings of $25 million per year for customers due to fewer minutes of interruption. The result of 155 minutes of interruption per customer is good news compared to prior years, but this statistic fluctuates from year to year based on weather conditions but is also impacted by the Company's increased expenses for tree trimming and capital expenditures to improve the Company's infrastructure. Company witness Kelly confirms as much in his testimony where he indicates "…SAIDI excluding MEDs has been consistently better than historical levels for the past three years, which indicates that the Company's reliability investments are delivering results."[147]

The Company's analysis does not take these factors into consideration and therefore, I place little value in the Company's analysis.

Ms. Meschke also calculates certain savings related to the Company's Culture Index based on purported cost savings from lower employee turnover. However, her Exhibit A-159 (AEM-4) shows that employee turnover was 2.6% in 2024 compared to 2.0% in 2021. Clearly, this is not an improving trend. To try and show the Company's better turnover experience, the Company makes a comparison to other utilities in this exhibit. However, while this information may be valid, it is not on-point with respect to the metric selected by the Company. Similar to her calculated assumed savings related to safety (discussed

[147] Michael Kelly direct testimony at page 25, lines 19 to 21.

above), Ms. Meschke assumes that the Company can reduce turnover in the employee category of "one to four years of tenure". She assumes a 2% reduction in turnover for this category and calculates savings of $7.1 million to $9.5 million annually. While she does not discuss how the Company can achieve this result in her testimony, this is nonetheless how she derives the potential savings she claims.

In summary, the cost savings calculated by Ms. Meschke are inconsistent with recent trends in performance, aspirational, and not based on actual achievements. They do not justify the $2.2 million of incentive compensation that the company seeks to recover in this rate case.

Q. BASED ON YOUR REVIEW OF RESULTS DURING THE PAST FIVE YEARS, HAS THE COMPANY ACHIEVED THE TARGET LEVEL OF PERFORMANCE FOR THE OPERATING MEASURES DURING THOSE YEARS?

A. No. In discovery, the Attorney General asked the Company to provide the target operating measures and the actual performance achieved for each year from 2020 to 2024. The information provided by the Company shows that in 2020 the Company only met 7 of the 9 operating measures at 100% of target or higher for an average rate of 78% of target. In 2021, only 6 of 9 measures were met at target or higher reflecting a 67% achievement rate. In 2022, 4 of the 6 operating measures were achieved at target or better reflecting a 67% achievement rate. In 2023, only 3 of the 6 operating measures were met at target or better reflecting a 50% achievement rate. In 2024, only 4 of the 6 measures were achieved at

target or better reflecting a 67% achievement rate. The average achievement rate for the past five years is 66%.[148]

Q. WHAT CONCLUSIONS AND RECOMMENDATIONS HAVE YOU REACHED WITH REGARD TO RECOVERY OF INCENTIVE COMPENSATION COSTS IN RATES?

A. As discussed above, the focus of the short-term incentive compensation plans is overwhelmingly directed at creating shareholder value, not customer benefits, and the officer group that directs the day-to-day operations is only minimally incentivized to meet operational goals. Certain design flaws with the EICP tend to reward mediocre performance and diminish any real customer benefits. Incentive compensation should be paid for exceptional performance, at least to pass the test of cost recovery in rates. Performance that is ordinary and achieves basic goals and efficient operations is paid for in base salaries.

Both management and other employees have received large annual merit salary increases since at least 2009. The Company argues that it must pay a competitive compensation package to retain talented management and employees. Although that may be the case, it does not mean that customers should pay for all or most of that expense. Shareholders also significantly benefit from talented management, perhaps even more so than customers. Customers are paying for higher base pay each year. Shareholders can share

[148] Exhibit AG-60.

the burden by paying for the incentive compensation that disproportionally favors their interests.

The Company's proposed incentive compensation expense of $2,211,000 for the projected test year assumes that the Company will achieve target performance for all its goals. There is no track record with the revised performance measures that supports that conclusion. It is probable that the Company may fall short of achieving 100% of the performance measures at target.

Although I do not believe the Company has made a compelling case to justify recovery of any amount of incentive compensation, I do, however, acknowledge that in recent rate cases the Commission has approved a portion of incentive compensation pertaining to operating measures. If the Commission decides to do the same in this case, I recommend that the Commission approve at most, recovery of $1,459,000 for incentive compensation based on achieving only 66% of the targeted performance measures over the past five years.[149] The Commission should exclude the remaining $752,000 from O&M expense for the projected test year.

E. O&M Adjustments - Summary

Q. PLEASE SUMMARIZE YOUR RECOMMENDED O&M ADJUSTMENTS.

[149] $2,211,000 x 66% = $1,459,000.

A. Operations and maintenance expenses represent a large part of the Company's cost structure. My analysis of the expense level proposed by the Company has shown that in the following areas these expenses are excessive or not needed and should be removed.

Summary of O&M Expense Reductions	Amount ($ Millions)
Electric Distribution	$ 42.3
Line Clearing Expense Deferred	76.5
IT Expense	18.3
Incentive Compensation	0.8
Total	$ 137.9

As such, I recommend that the Commission reduce the amount of total O&M costs proposed by the Company by $137.9 million and reduce the revenue deficiency accordingly. Exhibit AG-53 provides further details.

IX. Adjustments To Revenue Deficiency

Q. WHAT ARE THE TOTAL ADJUSTMENTS AND THE REVISED REVENUE DEFICIENCY YOU RECOMMEND?

A. Exhibit AG-58 summarizes the adjustments to rate base and operating income. The net result is a jurisdictional revenue deficiency of $15.7 million, which is a reduction of $278.2 million from the Company's requested level of $435.9 million.

I recommend the Commission adopt my proposed adjustments and issue an order granting rate relief to the Company no greater than $157.7 million.

X. Return on Deferred Line Clearing Costs

Q. WHAT RATE OF RETURN DO YOU PROPOSE SHOULD BE APPLIED TO THE DEFERRED LINE CLEARING COSTS FROM THE RAMP-UP IN EXPENSE?

A. I recommend that the Commission approve the use of the short-term debt rate approved in this rate case and that it be revised going forward for any changes to the short-term interest rate in future rate cases. In approving a similar surge in tree trimming cost in Case No. U-20162 for DTE Electric, the Commission established that the short-term interest rate was most appropriate during the time that the Company holds the costs in a regulatory asset and until those costs are financed through securitization. It is necessary to maintain consistent treatment between Consumers Energy and DTE Electric. Furthermore, the short-term interest rate is appropriate it reflects the short period that the costs will be held in the regulatory asset until securitization and will provide an added incentive to securitize the costs sooner than later.

In Exhibit AG-59, I calculated the appropriate return by using the 4.92% short-term interest rate included in Exhibit A-14, Schedule D1 multiplied by the average regulatory balance of $38,230,000 ($76,459,000 / 2) during the projected test year. The proposed return is $1,811,000. I recommend that the Commission approve this amount and methodology.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does. However, I reserve the right to amend, revise and supplement my testimony to incorporate new information that may become available.

MS. GILL: Your Honor, there was also some additional public records after AG-52, AG-53 through AG-60 were also public exhibits.

THE COURT: That was AG 53 through 63?

MS. GILL: Through 60 were public exhibits pre filed public exhibits.

THE COURT: Are there any objections to the admission of those exhibits?

Hearing none. Exhibits AG-53 through AG-60 are admitted.

(At 3:27 p.m., Exhibits AG-53 through AG-60 are admitted)

MS. GILL: Also. In lieu of examining certain Consumer's witnesses, the company agreed to the admission of certain discovery responses as exhibits which have been labeled AG-61 through AG-83 with AG-63 being confidential exhibit.

THE COURT: Are there any objections to the admission of these exhibits?

Hearing none. Exhibit AG-61, 62 and 64 through 83 are admitted to the public record and exhibit AG-63 is admitted to the confidential record.

(At 3:28 p.m. Exhibit AG-61, 62 and 64 through 83 are admitted to the public record and exhibit AG-63 is admitted to the confidential record)

MS. GILL: Thank you, Your Honor. That's

completes the Attorney General's case.

THE COURT: Thank you.

Anyone else present who wishes to bind in?

MS. HORNE: Your Honor, I could bind in Walmart's testimony.

THE COURT: All right. Please proceed.

MS. HORNE: Your Honor, Walmart, Inc. moves to bind in the direct testimony of Matthew T. Lyon filed in September 30, 2025, consisting of a cover page, a table of contents and 26 pages of questions and answers. Walmart also moves for the admission into the record of four exhibits, Exhibit WAL-1, a two page exhibit, exhibit WAL-2, a one page exhibit, Exhibit WAL-3, a four page exhibit, and exhibit WAL-4, a one page exhibit. Mr. Lyon did not file any rebuttal testimony. It is my understanding that no one wishes to cross-examine Mr. Lyon and that there is no objection to his testimony being bound in or to the exhibits being admitted. Accordingly Walmart requests that the testimony be bound in and the exhibits be admitted.

THE COURT: Are there any objections to the admission of this testimony or these exhibits?

Hearing none. The direct testimony of Matthew Lyon is bound into the record and Exhibits WAL-1 through WAL-4 are admitted.

(At 3:30 p.m., Exhibits WAL-1 through WAL-4 are admitted).

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-21870

DIRECT TESTIMONY AND EXHIBITS OF

MATTHEW T. LYON

ON BEHALF OF

WALMART INC.

SEPTEMBER 30, 2025

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Exhibit WAL-4: Calculation of Revenue Requirement Impact of Consumer's Proposed ROE-Projected 12-Month Period Ending April 30, 2027 vs. Average ROE Awards to Vertically Integrated Utilities Since 2023

I. Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Matthew T. Lyon. My business address is 2608 SE J Street, Bentonville, Arkansas 72716-0550. I am employed by Walmart Inc. ("Walmart") as Senior Manager, Utility Partnerships - Regulatory.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of Walmart.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I hold multiple degrees and a graduate certificate relevant to my work in energy, supply chains, and sustainability. My education includes a B.A. in Philosophy from Spring Hill College in 2004, an M.B.A. in Supply Chain Management from the University of Arkansas Walton College of Business in 2014, a Master of Public Service (M.P.S.) from the University of Arkansas Clinton School of Public Service, also completed in 2014, and a Graduate Certificate in Tropical Forest Landscapes: Conservation, Restoration, and Sustainable Use from Yale University School of the Environment, obtained in 2021. My professional experience spans 15 years in corporate sustainability, with a strong focus on transportation electrification, utility partnerships, and GHG emissions reduction. In 2010 and 2011 I worked as an Oil Spill Field Researcher on behalf of the National Oceanic Atmospheric Administration collecting data for a U.S. government impact study related to the BP/Deepwater Horizon Oil Spill. In 2012, I consulted Pan-Himalayan Grassroots

Development Foundation in Ranikhet, India on environmentally, economically, and socially sustainable development initiatives. From 2012 to 2016, I was the Lead Research Manager at The Sustainability Consortium where I worked with global companies to address environmental and social supply chain issues. In 2016 and 2017, I was the Principal at Versio Consulting where I served as an internal consultant for Walmart's global sustainability team on transformative supply chains. From 2017 to 2019, I was Manager of Supply Chains at Environmental Defense Fund working with Walmart to drive impacts on issues such as energy and transportation logistics. In 2022, I joined Walmart as Senior Manager of Zero Emissions Fleet Strategy at Walmart Inc. working primarily to accelerate transportation electrification across internal fleet and public EV charging. This involved distilling corporate goals, state-level compliance, incentives, and public utility regulatory proceedings into actionable plans. In 2024, I joined the Utility Partnerships - Regulatory team to support Walmart's intervention in public utility commission dockets focusing on transportation electrification, EV rates, Vehicle-to-Grid (V2G), Community Solar, and near-grid generation and energy storage systems. My Witness Qualifications Statement is attached as Exhibit WAL-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes, I submitted testimony in Case No. U-21860.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes, I have submitted testimony with the state regulatory commission for Indiana.

Q. ARE YOU SPONSORING EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS IN MICHIGAN.

A. As shown on Walmart's website, Walmart operates 117 retail units, two supply chain facilities, and employs over 35,000 associates in Michigan. In fiscal year ending 2025, Walmart purchased $4 billion worth of goods and services from Michigan-based suppliers, supporting more than 32,000 supplier jobs.[1]

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS WITHIN THE SERVICE TERRITORY FOR CONSUMERS ENERGY COMPANY ("CONSUMERS" OR "COMPANY").

A. Walmart has approximately 63 retail stores and related facilities in the Consumer's service territory. Primarily, these facilities are served on the Primary Demand ("Rate GPD"), General Service Primary Time-of-Use Rate ("Rate GPTU"), General Service Primary Rate ("Rate GP"), General Service Secondary Rate ("Rate GS"), and General Service Secondary Time-of-Use Rate ("Rate GPSU"). About 57

[1] https://corporate.walmart.com/about/location-facts/united-states/michigan

percent of Walmart's load is served by a third-party competitive supplier and the remainder takes generation service from Consumers.

II. Purpose of Testimony and Summary of Recommendations

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address aspects of the Company's Application for authority to increase its rates for the generation and distribution of electricity and for other relief filed with the Commission on March 28, 2025 ("Application"). Specifically, my testimony will provide recommendations to assist the Commission in its thorough and careful consideration of the customer impact of the Company's proposed rate increase and other relief.

Q. IN SETTING THE REVENUE REQUIREMENT, RETURN ON EQUITY ("ROE"), ALLOCATION, AND RATE DESIGN CHANGES FOR THE COMPANY, SHOULD THE COMMISSION CONSIDER THE IMPACT OF THE PROPOSED RATE INCREASE ON BUSINESS CUSTOMERS?

A. Yes. Electricity is a significant operating cost for retailers such as Walmart. When electric rates increase, the increased cost to retailers can put pressure on consumer prices and other expenses required by a business to operate. The Commission should thoroughly and carefully consider the impact on customers in examining the requested revenue requirement and ROE, in addition to all other facets of this case, to ensure that any increase in the Company's rates is the minimum amount necessary to provide safe, adequate, and reliable service, while also providing

Consumers with the opportunity to recover its reasonable and prudent costs and earn a reasonable return on its investment.

Q. PLEASE SUMMARIZE WALMART'S RECOMMENDATIONS TO THE COMMISSION.

A. Walmart's recommendations to the Commission are as follows:

(1) The Commission should thoroughly and carefully consider the impact on customers in examining the requested revenue requirement and ROE, in addition to all other facets of this case, to ensure that any increase in the Company's rates reflects the minimum amount necessary to compensate the Company for adequate and reliable service, while also providing Consumers an opportunity to earn a reasonable return for its shareholders.

(2) The Commission should closely examine Consumer's proposed revenue requirement increase and the associated ROE, especially when viewed in light of:

(a) the impact of the resulting revenue requirement increase on customers;

(b) the reduced risk associated with Michigan's regulatory framework and Commission precedent, including the (i) use of a projected test year (which reduces the risk due to regulatory lag based on the inclusion of the most current information in its rates when they will be in effect), (ii) inclusion of Construction Work in Progress ("CWIP") in rate base, and (iii) alternative recovery mechanisms

such as the currently approved Distribution Investment Recovery Mechanism ("IRM") Surcharge; and

(c) recent ROEs approved in Michigan and other jurisdictions nationally.

(3) For purposes of this case, Walmart does not take a position on the Company's proposed cost of service model at this time. However, to the extent that alternative cost of service models or modifications to the Company's proposed models are proposed by other parties, Walmart reserves the right to address any such changes in accord with the Commission's procedures in this docket.

(4) For the purposes of this case, Walmart does not take a position on the rate design proposals and does not oppose otherwise maintaining the current rate design for secondary and primary customers.

(5) Walmart recommends that the Commission require the Company to work with interested stakeholders to develop a new EV tariff that encourages investment specifically for third party-owned public-facing EV Direct Current Fast Chargers ("DCFC") stations and to seek Commission approval of such in its next general rate case.

Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY THE COMPANY INDICATE WALMART'S SUPPORT?

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any filed position.

III. Revenue Requirement and ROE

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED REVENUE REQUIREMENT INCREASE?

A. My understanding is that the Company requests jurisdictional rate relief in the amount of $436 million and collection of $24 million associated with the deferred costs related to distribution investments made during the 12 months ended February 28, 2025, totaling $460 million in jurisdictional rate relief.[2]

Q. WHAT IS THE COMPANY'S PROPOSED ROE IN THIS CASE?

A. Consumers proposes an ROE of 10.25 percent, based on the Company's proposed range of 10.25 percent to 11.25 percent.[3] Based on a capital structure of 50.75 percent equity, the proposed ROE results in an overall rate of return of 6.35 percent on an after-tax basis.[4]

[2] *See* Direct Testimony of Heidi J. Myers ("Myers Direct") p. 5, line 3.
[3] *See* Direct Testimony of Ann E. Bulkley ("Bulkley Direct"), p. 5, lines 5-6.
[4] *See* Exhibit No. A-14 (MRB-1), Schedule D-1, p. 1.

Q. HOW DOES THE PROPOSED ROE COMPARE TO THE COMPANY'S CURRENTLY APPROVED ROE?

A. The proposed ROE is 35 basis points higher than the ROE of 9.90 percent approved by the Commission on March 21, 2025.[5]

Q. TAKING INTO CONSIDERATION THE ROE PROPOSAL MADE BY THE COMPANY, IS WALMART CONCERNED THAT THE ROE IS EXCESSIVE?

A. Yes. Walmart believes that the Company's proposed ROE of 10.25 percent is excessive, especially in light of:

(1) the customer impact of the resulting revenue requirement increase as discussed below;

(2) the reduced risk associated with Michigan's regulatory framework and Commission precedent, including the (i) use of a projected split-test year (which reduces the risk due to regulatory lag based on the inclusion of the most current information in its rates when they will be in effect), (ii) inclusion of CWIP in rate base, and (iii) alternative recovery mechanisms such as the currently approved Distribution IRM Surcharge; and

(3) the reported average ROE authorized for regulated utilities in Michigan and the United States for the last two or more years.

[5] *In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief,* Case No. U-21585, Order issued March 21, 2025 ("2025 Order"), p. 253.

(A) Customer Impact

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S CURRENTLY APPROVED ROE?

A. As stated above, my understanding is the Company's currently approved ROE is 9.90 percent as authorized by the Commission just one year ago in Case No. U-21585.[6]

Q. HAVE YOU CALCULATED AN ESTIMATE OF THE IMPACT OF THE RETURN ON RATE BASE FROM THE COMPANY'S PROPOSED INCREASE IN ROE FROM 9.90 PERCENT TO 10.25 PERCENT?

A. Yes. Using the Company's proposed rate base, cost of debt, and capital structure, the impact of the changes resulting from proposed ROE alone is approximately $30.8 million, or 7.06 percent of the proposed revenue deficiency.[7]

(B) Regulatory Framework

Q. HAS THE COMMISSION RECOGNIZED THE EFFECT OF MICHIGAN'S REGULATORY FRAMEWORK ON UTILITY RISK?

A. Yes. In the Order in Case No. U-16472, the Commission stated:

> Act 286 (1) allows Michigan utilities to use projected test year revenues, expenses, and sales volumes in support of any requested rate increases, (2) provides for the possibility of self-implementation of all or part of a

[6] *See* 2025 Order, p. 253.
[7] Exhibit WAL-2.

> requested rate change within 180 days following submission of an application, (3) requires that the Commission issue a final order concerning the application within 365 days from its filing, lest the request be automatically implemented, and (4) restricts the amount of retail choice to 10% of a utility's total sales. These changes in Michigan's regulatory framework, which tend to lean heavily in favor of the utilities and their investors by significantly reducing the risk borne by such companies in the past, necessitate taking a conservative approach with regard to the specific ROE authorized in rate cases like this. *See*, October 20, 2011, order in Case Nos. U-16472 and U-16489, page 39 (citing Proposal for Decision, Case Nos. U-16742 and U-16489, August 12, 2011, page 49).

Q. SHOULD THE COMMISSION CONTINUE TO RECOGNIZE THE EFFECT OF MICHIGAN'S REGULATORY FRAMEWORK ON UTILITY RISK?

A. Yes. The Commission should continue to recognize the effect of Michigan's regulatory framework on utility risk. In addition to those characteristics outlined in its Order in Case No. U-16472, the Commission should also consider the risk reducing impact of including CWIP in rate base when setting ROE.

(C) Recent ROEs Approved by the Commission

Q. IS THE COMPANY'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN THE ROEs APPROVED BY THIS COMMISSION FROM 2023 TO PRESENT?

A. Yes. Since 2023, this Commission has issued orders with stated ROEs in nine cases, with the most recent ROE approved earlier this year. The average of these approved

ROEs is 9.89 percent.[8]

Q. IN WHICH OTHER CASES DID THE COMMISSION ISSUE ORDERS WITH STATED ROES?

A. The Commission issued orders with stated ROEs in the following cases:[9]

- Case No. U-21224, the Company's general rate case that completed in 2023, in which the Commission approved an ROE of 9.90 percent.
- Case No. U-21286, Upper Peninsula Power Co.'s general rate case that completed in 2023, in which the Commission approved an ROE of 9.90 percent.
- Case No. U-21297, DTE Electric Co.'s general rate case that completed in 2023, in which the Commission approved an ROE of 9.90 percent.
- Case No. U-21389, the Company's general rate case that completed in 2024, in which the Commission approved an ROE of 9.90 percent.
- Case No. U-21461, Indiana Michigan Power Co.'s general rate case that completed in 2024, in which the Commission approved an ROE of 9.86 percent.
- Case No. U-21555, Upper Peninsula Power Co.'s general rate case that completed in 2024, in which the Commission approved an ROE of 9.86 percent.

[8] Exhibit WAL-3.
[9] *Id.*

- Case No. U-21541, Upper MI Energy Resources Corp.'s general rate case that completed in 2024, in which the Commission approved an ROE of 9.86 percent.
- Case No. U-21534, DTE Electric Co.'s general rate case that completed in 2024, in which the Commission approved an ROE of 9.90 percent.
- Case No. U-21585, the Company's last general rate case that completed in 2025, in which the Commission approved an ROE of 9.90 percent.

As such, the Company's proposed 10.25 percent ROE is counter to recent Commission actions regarding ROE.

(D) National Utility Industry ROE Trends

Q. IS THE COMPANY'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN THE ROEs APPROVED BY OTHER UTILITY REGULATORY COMMISSIONS SINCE 2023?

A. Yes. According to data from S&P Global Market Intelligence ("S&P Global"), a financial news and reporting company, the average of the 104 reported electric utility rate case ROEs authorized by commissions to investor-owned utilities since 2023 is 9.68 percent.[10] The range of reported authorized ROEs for the period is 8.63 percent to 11.45 percent, and the median authorized ROE is 9.70 percent.[11]

[10] Exhibit WAL-3.
[11] Exhibit WAL-3.

The average and median values are significantly below the Company's proposed ROE of 10.25 percent. As such, the Company's proposed 10.25 percent ROE is counter to broader electric industry trends.

Q. WHY IS WALMART PROVIDING INFORMATION ON THE REPORTED AVERAGE ROE AUTHORIZED FOR REGULATED UTILITIES IN THE UNITED STATES FOR THE LAST TWO OR MORE YEARS?

A. Walmart is providing this information to comply with the Amended Scheduling Memorandum issued by the ALJ on September 5, 2025, which requires that any party submitting testimony regarding the authorized ROE requested by the utility in this case shall submit direct or rebuttal testimony and any supporting exhibits which set forth the reported average ROE authorized for regulated utilities in the United States for the last two or more years.[12]

Q. SEVERAL OF THE REPORTED AUTHORIZED ROEs ARE FOR DISTRIBUTION-ONLY UTILITIES OR FOR ONLY A UTILITY'S DISTRIBUTION SERVICE RATES. WHAT IS THE AVERAGE AUTHORIZED ROE IN THE REPORTED GROUP FOR VERTICALLY INTEGRATED UTILITIES?

A. In the group reported by S&P Global, the average ROE authorized for vertically

[12] *In the matter of the complaint of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief,* Case No. U-21870, Amended Scheduling Order, p. 2.

integrated utilities since 2023 is 9.77 percent.[13] The average ROE authorized for vertically integrated utilities is (i) 9.71 percent in 2023, (ii) 9.85 percent in 2024, and (iii) 9.74 percent so far in 2025.[14] As such, the Company's proposed 10.25 percent ROE is counter to broader electric industry trends. In fact, as shown in Figure 1, the Company's proposed ROE would be the sixth highest approved ROE for a vertically integrated utility from 2022 to present if approved by the Commission.

[13] Exhibit WAL-3..
[14] Exhibit WAL-3.

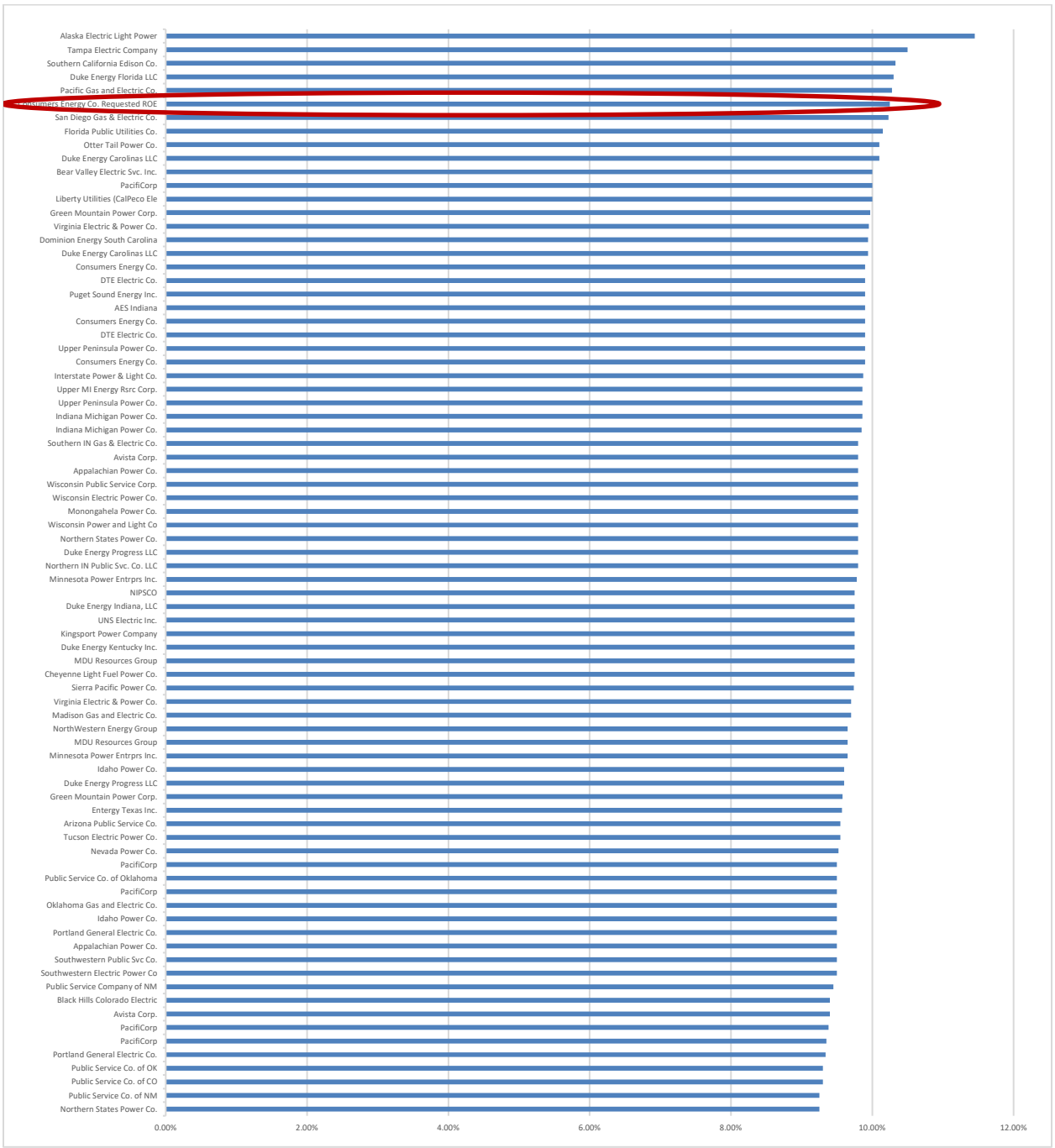


Figure 1. Consumer's Proposed ROE Versus Authorized ROEs for Vertically Integrated Utilities, 2023 to Present. Source: Exhibit Exhibit WAL-3.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT IF THE COMMISSION WERE TO AWARD AN ROE OF 9.77 PERCENT, THE AVERAGE ROE AWARDED FOR VERTICALLY INTEGRATED UTILITIES FROM 2023 TO PRESENT?

A. Using the Company's proposed rate base, cost of debt, and capital structure, awarding Consumers an authorized ROE of 9.77 percent instead of the requested 10.25 percent would result in a reduction to the requested revenue requirement increase of about $42.4 million. This represents about a 9.73 percent reduction from the Company's requested revenue requirement increase.[15]

Q. IS WALMART RECOMMENDING THAT THE COMMISSION BE BOUND BY ROEs AUTHORIZED BY OTHER STATE REGULATORY AGENCIES?

A. No. Decisions of other state regulatory commissions are not binding on the Commission. Additionally, each commission considers the specific circumstances in each case in its determination of the appropriate ROE. Walmart is providing this information to illustrate a national customer perspective on industry trends in authorized ROE, which has a demonstrable effect on revenue requirement and the burden on customers.

[15] Exhibit WAL-4.

(E) Reported Return on Equity for the United States Stock Market

Q. WHAT IS THE REPORTED FORECASTED RETURN ON EQUITY FOR THE UNITED STATES STOCK MARKET?

A. According to Vanguard, the 10-year annualized nominal return and volatility forecast for U.S. equities ranges from 3.3 to 5.3 percent, based on the June 30, 2025 running of the Vanguard Capital Markets Model®, as shown in Figure 2.

EQUITIES	RETURN PROJECTION	MEDIAN VOLATILITY
U.S. equities	3.3%–5.3%	15.2%
Global equities ex-U.S. (unhedged)	5.1%–7.1%	18.8%
Developed markets ex-U.S. equities (unhedged)	5.7%–7.7%	18.2%
Emerging markets equities (unhedged)	3.1%–5.1%	25.3%
U.S. value	5.8%–7.8%	18.7%
U.S. growth	1.9%–3.9%	16.2%
U.S. large-cap	3.1%–5.1%	15.0%
U.S. small-cap	5.0%–7.0%	19.9%
U.S. real estate investment trusts	3.0%–5.0%	18.4%
FIXED INCOME		
U.S. aggregate bonds	4.0%–5.0%	6.3%
Global ex-U.S. aggregate bonds (hedged)	4.3%–5.3%	4.9%
U.S. Treasury bonds	3.8%–4.8%	6.7%
U.S. credit	4.2%–5.2%	6.5%
U.S. high-yield corporate bonds	4.7%–5.7%	9.7%
Emerging markets sovereign bonds	5.4%–6.4%	11.2%
U.S. Treasury Inflation-Protected Securities	2.8%–3.8%	5.1%
U.S. mortgage-backed securities	4.4%–5.4%	4.2%
U.S. municipal bonds	3.5%–4.5%	4.8%
U.S. high-yield municipal bonds	4.0%–5.0%	7.8%
U.S. cash	3.0%–4.0%	1.1%
U.S. municipal cash	2.5%–3.5%	0.5%
U.S. COMMODITIES	4.5%–6.5%	16.7%
U.S. INFLATION	1.5%–2.5%	1.8%
VANGUARD U.S. DOLLAR INDEX	−0.7%–0.3%	8.4%

Figure 2. Vanguard's outlook for financial markets, as presented on Sept. 26, 2025 from: https://advisors.vanguard.com/insights/article/series/market-perspectives

Q. DOES WALMART RECOMMEND THAT THE COMMISSION APPROVE AN ROE THAT ALIGNS WITH THIS FORECAST?

A. No. Walmart is not intervening as a forecasting expert on future returns of varying equity markets, and therefore makes no recommendation based on this information.

Q. **WHY IS WALMART PROVIDING THIS REPORTED RETURN ON EQUITY FOR THE UNITED STATES STOCK MARKET?**

A. Walmart is providing this information to comply with the Amended Scheduling Memorandum issued by the ALJ on September 5, 2025, which requires that any party submitting testimony regarding the authorized ROE requested by the utility in this case shall submit direct or rebuttal testimony and any supporting exhibits which set forth the reported forecasted return on equity for the United States stock market.[16]

(F) Conclusion

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION IN REGARD TO THE COMPANY'S PROPOSED ROE?

A. The Commission should closely examine Consumer's proposed revenue requirement increase and the associated ROE, especially when viewed in light of:

(1) the impact of the resulting revenue requirement increase on customers;

[16] *In the matter of the complaint of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief,* Case No. U-21870, Amended Scheduling Order, p. 2.

(2) the reduced risk associated with Michigan's regulatory framework and Commission precedent, including the (i) use of a projected test year (which reduces the risk due to regulatory lag based on the inclusion of the most current information in its rates when they will be in effect), (ii) inclusion of CWIP in rate base, and (iii) alternative recovery mechanisms such as the currently approved Distribution IRM Surcharge; and

(3) recent ROEs approved in Michigan and other jurisdictions nationally.

IV. Cost of Service and Rate Design

(A) Proposed Changes to Cost of Service

Q. WHAT IS WALMART'S POSITION ON SETTING RATES BASED ON THE UTILITY'S COST OF SERVICE?

A. Walmart advocates that rates be set based on the utility's cost of service for each rate class. This produces equitable rates that reflect cost causation, send proper price signals, and minimize price distortions.

Q. IS THE COMPANY PRESENTING A COST OF SERVICE STUDY ("COSS") IN THIS RATE CASE?

A. Yes, it is. It is my understanding that the Company is sponsoring a COSS for the projected test year, which covers the 12-month period ending April 30, 2027.[17] It is also my understanding that the Company is sponsoring two additional versions

[17] *See* Direct Testimony of Emily A. Davis, p. 2, lines 9-10.

of the COSS, with the Version 1 study employing the methodologies previously approved in the Company's last general rate case, Case No. U-21585.[18] The Version 2 study starts with the Version 1 COSS and incorporates Company proposals to revise the allocation of: (i) Customer Advances, and (ii) Overhead Line Operating and Maintenance Expenses.[19] It is my understanding that the Company is relying on the Version 2 COSS for its revenue allocation and rate design.

Q. DOES WALMART TAKE A POSITION ON THE COMPANY'S PROPOSED COST OF SERVICE METHODOLOGY AT THIS TIME?

A. No. However, to the extent that alternative cost of service methodologies or modifications to the Company's methodology are proposed by other parties, Walmart reserves the right to address any such changes in accordance with the Commission's procedures in this Case.

[18] *See* Direct Testimony of Emily A. Davis, p. 2, lines 19-21.
[19] *See* Direct Testimony of Emily A. Davis, p. 2, lines 19-24; p. 3, line 1.

(B) General Rate Design Changes

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE SECONDARY RATE STRUCTURE?

A. No. The Company is proposing to maintain its current rate structure for secondary customers.[20]

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE PRIMARY RATE STRUCTURE FOR RATES GP, GPD, OR GPTU?

A. No. The Company is not proposing any changes to the rate structure for Primary Rates GP, GPD, OR GPTU.[21]

Q. WHAT IS WALMART'S RECOMMENDATION TO THE COMMISSION ON THE COMPANY'S RATE DESIGN PROPOSALS FOR ITS SECONDARY AND PRIMARY CUSTOMERS?

A. For the purposes of this case, Walmart does not take a position on the rate design proposals as described above and does not oppose otherwise maintaining the current rate design for secondary and primary customers.

[20] *See* Direct Testimony of Laura M. Connolly, p. 10, lines 21-22.
[21] *See* Direct Testimony of Laura M. Connolly, p. 11, lines 3-4.

(C) Public EV Charging Rates

Q. DOES THE COMPANY CURRENTLY OFFER TARIFFS SPECIFICALLY FOR THIRD PARTY-OWNED EV DCFC STATIONS?

A. Based on my understanding, it does not appear that the Company currently offers a rate specifically for third party-owned public EV DCFC stations.

Q. ARE THERE CERTAIN EV RATE STRUCTURES THAT THE COMMISSION SHOULD CONSIDER WITH REGARD TO THIRD PARTY-OWNED PUBLIC EV DCFC STATIONS?

A. Yes, there are. The Company should offer a rate structure that encourages investment for business customers who are interested in owning and operating public EV DCFC equipment and stations. These rates should be volumetric in nature and created in such a way to collect cost without cross subsidization but while also providing the best use case for the DCFC owner operator.

Q. WHY DOES WALMART BELIEVE THAT THE COMPANY SHOULD OFFER A RATE FOR THIRD-PARTY OWNED PUBLIC EV DCFC STATIONS?

A. Building a strong public network of DC fast chargers is essential for supporting the EV industry and encouraging the transition to EVs. This network helps eliminate range anxiety and other challenges that EV drivers face when charging, making the experience more comparable to refueling a traditional gasoline car. To meet the growing need for EV chargers in the Company's service area, the number of public-facing DC fast chargers must increase. This requires new initiatives and rate

structures to build a robust public DCFC network. Discussed in more detail below, a key factor in attracting third-party investment in these public chargers is offering specific EV-friendly rate options.

Q. DOES WALMART HAVE EXPERIENCE IN THE EV CHARGING SPACE?

A. Yes, Walmart has substantial experience with offering EV charging to its customers and is actively growing its presence in the EV charging space. Specifically, Walmart currently hosts more than 1,200 public DCFCs at 285 different locations across 43 states. As announced in April 2023, Walmart intends to build its own EV fast-charging network at thousands of Walmart and Sam's Club locations across the U.S. over the next few years. Walmart retail sites are ideally situated for EV charging stations because of their large parking lots, easy public access, and multi-site locations.

Q. ARE WALMART-OWNED AND OPERATED CHARGERS NOW AVAILABLE TO THE PUBLIC?

A. Yes. Walmart opened its first Walmart-owned and operated charging station in McKinney, Texas[22] in March 2025, and since then we have opened several more stations in the Dallas area. The base configuration of our charging stations is eight stalls supplied by four 400 kW units with two handles each. Depending on the site, additional units may be added.

[22] https://www.walmart.com/store/206-mckinney-tx/ev-charging-station

Q. WHY HAS WALMART DECIDED TO PARTICPATE IN THE PUBLIC EV DCFC SPACE?

A. In support of its clean energy and carbon reduction goals, Walmart is committed to building its own EV fast charging network, which also supports the growth of the nation's overall EV infrastructure. By installing fast charging stations at thousands of locations, Walmart supports EV drivers in local communities and along major travel corridors, a crucial combination for encouraging more people to choose an electric vehicle. Walmart is proud to offer EV fast charging as a convenient, reliable, and affordable service for its current EV-driving customers, as well as future EV drivers.

Q. ARE ELECTRIC RATES A FACTOR THAT WALMART CONSIDERS WHEN INSTALLING OR SITING EV CHARGING INFRASTRUCTURE AT ITS FACILITIES?

A. Yes, Walmart seeks to balance the risks and costs of installing and maintaining a particular EV fast charging station, which is informed, in part, by the tariff under which the electricity is provided from the utility to the owner of the EV fast charging station.

Q. SHOULD THE COMMISSION REQUIRE THE COMPANY TO DEVELOP AN EV CHARGING-SPECIFIC RATE FOR THIRD PARTY-OWNED PUBLIC EV DCFC STATIONS?

A. Yes, it should. In the short term, public EV charging-specific rates are needed to support third-party investment in EV charging equipment. As an investor in EV

charging equipment for both the public and its own private fleet, Walmart understands how EV charging rates can either promote or impede EV charging investment and user experience. While the EV industry continues to grow, there will still be a ramp-up to sufficient EV adoption to support an extensive public EV charging network. This will create geographical locations where public EV chargers are either not being used or are used infrequently. For these under-utilized chargers that are being billed by the utility under a more traditional rate tariff with a demand charge, the charger operator may be assessed the maximum demand charge even after only a single use of that charging unit regardless of whether there is any additional charging during that month. This outcome negatively impacts the economics for that unit and may lead to little or no third-party investment in public EV chargers sited in areas of initial low usage.

Q. WHAT IS WALMART'S RECOMMENDATION TO THE COMMISSION WITH REGARD TO DEVELOPING AN EV RATE SPECIFICALLY FOR THIRD PARTY-OWNED PUBLIC EV DCFC STATIONS?

A. Walmart recommends that the Commission require the Company to work with interested stakeholders to develop a new EV tariff that encourages investment specifically for third party-owned public-facing EV DCFC stations and to seek Commission approval of such in its next general rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. HORNE: Thank you.

THE COURT: Is there anyone else present who wishes to bind in?

All right. Hearing and seeing none. I think we don't have much choice but to adjourn for the day and we will reconvene tomorrow. We are off the record.

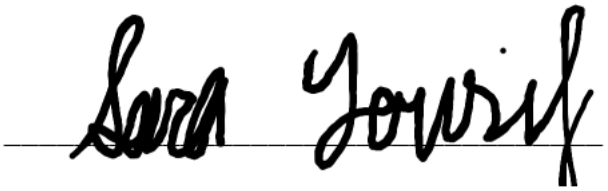
(Off the record at 3:31 p.m.)

STATE OF MICHIGAN)
)ss
COUNTY OF OAKLAND)

CERTIFICATION

I certify that this transcript, consisting of 143 pages, is a complete, true, and correct record of the matter of Case No. U-21870, before Jonathan Thoits, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Tuesday, November 4, 2025.

I also certify that I am not a relative of, employee of, or an attorney for a party; nor am I financially interested in the action.



Sara Yousif, CER 16328
Notary Public, Macomb County, Michigan
My Commission Expires: 09/06/30