S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of **CONSUMERS ENERGY COMPANY's** application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.	Case No. U-21816

At the September 11, 2025 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Katherine L. Peretick, Commissioner
Hon. Shaquila Myers, Commissioner

ORDER

History of Proceedings

On November 15, 2024, Consumers Energy Company (Consumers) filed an application in this case, with supporting testimony and exhibits, pursuant to Public Act 295 of 2008 (Act 295), as amended by Public Act 235 of 2023 (Act 235), MCL 460.1022(3) requesting approval of an amendment to the company's renewable energy plan (REP).

A prehearing conference was held on January 8, 2025, before Administrative Law Judge Jonathan F. Thoits (ALJ) at which the ALJ recognized the intervention of the Michigan Department of Attorney General (Attorney General), and granted petitions to intervene filed by the Association of Businesses Advocating Tariff Equity (ABATE); Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, and Vote Solar (collectively, the Clean Energy Organizations or CEOs); Great Lakes Renewable Energy Association, Inc. (GLREA); Hemlock Semiconductor Operations LLC; Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United (collectively, MEIU); Michigan Environmental Council (MEC); and Cadillac Renewable Energy L.L.C., Genesee Power Station Limited Partnership, Grayling Generating Station Limited Partnership, T.E.S. Filer City Station Limited Partnership, and National Energy of McBain, LLC (collectively, Biomass Merchant Plants or BMPs). Consumers and the Commission Staff (Staff) also participated in the proceeding. A schedule for the case was established by the ALJ.

On January 16, 2025, the Natural Resources Defense Council (NRDC) filed a petition to intervene out of time. No objection was entered and on January 30, 2025, the ALJ granted NRDC's petition.

On January 21, 2025, the ALJ adopted a protective order for use in this matter.

On February 28, 2025, the Attorney General filed a motion to compel discovery responses from Consumers, and the company filed a response to the motion on March 5, 2025.

On March 12-13, 2025, direct testimony and exhibits were filed by the Staff, the Attorney General, ABATE, the BMPs, the CEOs, GLREA, MEC/NRDC, and MEIU, some of which were filed confidentially. On April 8, 2025, Consumers, the Staff, ABATE, the BMPs, the CEOs, and GLREA filed rebuttal testimony and exhibits. On April 9 and 17, 2025, the BMPs filed corrected direct testimony and exhibits. On April 11, 2025, ABATE filed revised exhibits. Consumers filed revised testimony and exhibits on April 18, 2025.

Evidentiary hearings were held on April 21 and 24, 2025, wherein testimony and exhibits were bound into the record and cross-examination took place.

Consumers, the Staff, the Attorney General, ABATE, the BMPs, the CEOs, GLREA, MEC/NRDC, and MEIU filed initial briefs on May 21, 2025. On June 10, 2025, Consumers, the Attorney General, ABATE, the BMPs, the CEOs, GLREA, MEC/NRDC, and MEIU filed reply briefs. The Staff filed a letter stating that it would not be filing a reply brief.

The ALJ issued a Proposal for Decision (PFD) on August 1, 2025. On August 11, 2025, Consumers, the Staff, the Attorney General, the BMPs, the CEOs, GLREA, MEC/NRDC, and MEIU filed exceptions to the PFD. On August 18, 2025, Consumers, the Attorney General, ABATE, GLREA, MEC/NRDC, and MEIU filed replies to exceptions. The BMPs filed a letter stating that they would not be filing replies to exceptions.

The record consists of testimony from 10 witnesses contained within 884 pages of public and confidential transcript, along with 105 exhibits (inclusive of schedules). The docket also contains a public comment, which can be viewed in the section of the docket labeled "Case Comments." *See*, Case No. U-21816, filing #U-21816-0001-CC (as of September 10, 2025).

Statutory Requirements

Pursuant to Act 295, electric providers must maintain REPs that meet certain renewable energy credit (REC) portfolio standards (RPSs). Section 28 of Act 295, as amended by Act 235, MCL 460.1028, requires electric providers to achieve an RPS of 15% through 2029, 50% in 2030 through 2034, and 60% in 2035 and each year thereafter. Electric providers must meet the RPS with RECs obtained by any of the following means:

> (a) Generating electricity from renewable energy systems for sale to retail customers.
> (b) Purchasing or otherwise acquiring renewable energy and capacity.
> (c) Purchasing or otherwise acquiring renewable energy credits without the associated renewable energy or capacity. Renewable energy credits acquired under this subdivision shall be produced within the territory of the regional transmission organization of which the electric provider is a member, and, except for a municipally owned electric utility, shall not exceed 5% of an electric provider's

> renewable energy credits annually used to comply with the renewable energy standard. Renewable energy credits acquired under this subdivision are not subject to the requirements of section 29 and shall not be used to comply with the renewable energy standard after 2035.

MCL 460.1028(5).

In addition, MCL 460.1022(3) states, in relevant part, that:

> [w]ithin 1 year after the effective date of the amendatory act that added section 51, and within 2 years after the commission issues an order approving the electric provider's last amended renewable energy plan, an electric provider shall file an amended renewable energy plan that includes a forecast of the renewable energy resources needed to comply with the renewable energy credit standard pursuant to a filing schedule established by the commission. For an electric provider whose rates are regulated by the commission, the commission shall conduct a contested case hearing on the amended renewable energy plan pursuant to the administrative procedures act of 1969, 1969 PA 306, MCL 24.201 to 24.328. After the hearing, the commission shall approve, with any changes consented to by the electric provider, or reject the amended renewable energy plan. For all other electric providers, the commission shall provide an opportunity for public comment on the amended renewable energy plan. After the applicable opportunity for public comment, the commission shall determine whether any amendment to the renewable energy plan proposed by the provider complies with this act. For alternative electric suppliers, the commission shall approve, with any changes consented to by the electric provider, or reject any proposed amendments to the renewable energy plan. For each amended renewable energy plan filed by an electric provider, the commission shall issue a final order within 300 days after the date the amended renewable energy plan was filed with the commission.

Further, MCL 460.1022 states that:

> (5) For an electric provider whose rates are regulated by the commission, the commission shall approve amendments to the renewable energy plan if the commission determines both of the following:
>
> (a) That the amended renewable energy plan is reasonable and prudent. In making this determination, the commission shall take into consideration projected costs and whether or not projected costs in prior amended renewable energy plans were exceeded.
>
> (b) That the amended renewable energy plan is consistent with the purpose set forth in section 1(2) and meets the renewable energy credit standard.
>
> (6) For an electric provider whose rates are regulated by the commission, the commission shall review the projected costs of the renewable energy plan and

> approve, in whole or in part, the projected costs if the commission finds those projected costs, in whole or in part, to be reasonable and prudent. In making this determination, the commission shall consider whether projected costs in prior renewable energy plans were exceeded.

Following the enactment of Act 295, Consumers filed its REP on February 17, 2009, in Case No. U-15805, which was approved by the Commission on May 26, 2009. The company's REP has subsequently been amended and it contains several amendments that were approved by the Commission, most recently in Case No. U-21374.

On February 8, 2024, the Commission issued an order in Case No. U-21568 requiring Consumers to file its amended REP no later than November 15, 2024. In that same case, the Commission also approved Filing Requirements and Instructions for Renewable Energy Plans for Michigan Investor-Owned Retail Rate-Regulated Electric Utilities. Accordingly, Consumers filed its amended REP in this docket on November 15, 2024.

<u>Consumers Energy Company's Proposed Amended Renewable Energy Plan</u>

As an initial matter, the Commission notes that although several intervenors objected to Consumers' proposed amended REP, the intervenors' objections were limited to specific portions—not the entirety—of the company's amended REP. Therefore, the Commission finds that the undisputed portions of Consumers' REP are approved and shall not be addressed in detail in this order.

1. Renewable Energy Credit Portfolio Standard

   a. Distributed Generation Renewable Energy Credits

Consumers noted that its REC portfolio must be calculated using:

> [t]he average number of megawatt hours [(MWh)] of electricity sold by the electric provider annually during the previous 3 years to retail customers in this state, less the amount of sales attributable to customers participating in an electric provider's voluntary green pricing [(VGP)] program under section 61 and the outflow from

> customers participating in the distributed generation [(DG)] program under section 173 for that year.

2 Tr 50-51 (quoting MCL 460.1028(b)(ii)). To calculate the number of MWh of electricity sold by the company, less the MWh of sales attributable to customers participating in Consumers' DG program, the company provided a projection for DG in Exhibit A-3. The company stated that "[t]he projection reflects outflow from both the Company's legacy net metering program and the Company's DG program, as defined in Section C11.3 of the Company's electric rate book. The DG outflow forecast specifically relies on the actual data for the two program types from 2022 and 2023." 2 Tr 51. Consumers contended that the projections do not include any generation consumed by the customers for their own use; rather, the forecast only includes excess generation that is sent to the grid. *See*, Consumers' initial brief, p. 8.

GLREA noted that Consumers' proposed amended REP includes an increasing amount of REC purchases. GLREA asserted that the Commission should require Consumers to purchase RECs from projects that fall under the DG program and the Public Utility Regulatory Policies Act of 1978 (PURPA) before they purchase out-of-state RECs, so long as the cost of the RECs from the DG and PURPA projects is less than or equal to out-of-state RECs. *See*, 4 Tr 621; GLREA's initial brief, pp. 17-18. In addition, GLREA stated that DG RECs could "be used to meet non-contracted VGP customer demand." 4 Tr 589.

The Staff noted that in Case No. U-21375, it analyzed the effect of using DG RECs for VGP or RPS compliance. The Staff explained that it:

> developed a simplified model using the RPS requirements, as well as the obligation to serve load, to isolate what effect using DG RECs for either VGP or RPS compliance would have on the total number of renewables required to meet the RPS requirement. In this simplified model, the only independent variable was the amount of DG on the system and it was assumed for simplicity that all DG RECs were used if they were available. There were five different cases considered by Staff; Case A is a case were no DG RECs are used for either compliance with RPS

> or VGP, Case B is were DG outflow RECs are used for satisfying VGP load, Case C is where DG outflow RECs are used for satisfying RPS Compliance, Case D is where DG RECs from both outflow and RECs from DG generation that is consumed onsite are used for RPS compliance, and Case E is a case in which there was assumed to be no VGP load and no DG RECs were used either for RPS Compliance or VGP load.

4 Tr 854-855 (footnotes omitted). The Staff stated that "[t]he simplified model showed mathematically that, all else being equal, the use of DG RECs either for VGP or RPS compliance reduces the total number of renewables on the system required to meet the RPS and VGP requirement." 4 Tr 855 (footnote omitted).

The Staff also asserted that if the energy produced from DG is consumed onsite and is offsetting the load Consumers would otherwise need to serve, the generation cannot also count as RECs that can be sold to another entity. The Staff explained that "RECs are a commodity that represents the 'renewable attribute' of generation which we have separated from the energy that is actually produced. This arrangement makes sense because you cannot have electron traceability on the wider bulk electric system." Staff's initial brief, pp. 18-19 (citing 5 Tr 855). Thus, the Staff argued that if the DG RECs that are consumed onsite are sold to another entity, the generation would no longer be considered "renewable" because the renewable attribute of the generation has been sold and the generation would no longer be eligible for the DG program. More specifically, the Staff asserted that:

> [Act] 235 requires that in order to be eligible for the DG program, customers must utilize an eligible electric generator. [Act] 235 at MCL 460.1005(e) defines an eligible electric generator as a methane digestor or a renewable energy system. Staff witness Zachary C. Heidemann testified that if the customer has sold their RECs then they no longer own the RECs associated with generation that is consumed onsite and therefore it is no longer an eligible electric generator.

Staff's initial brief, p. 19 (citing 4 Tr 856). The Staff stated that because no other renewable resource that uses onsite generation is considered renewable after the RECs it generates are sold, DG should be treated the same. In the event the Commission finds that the purchase of DG RECs is not double-counting, the Staff requested that the Commission find that "DG RECs should only be sold to the Company at the Company's discretion, with a reasonable rationale for doing so." Staff's initial brief, p. 21.

Furthermore, the Staff noted that, pursuant to Act 235, a DG customer "shall own any renewable energy credits granted for electricity generated on the customer's site under the distributed generation program . . . ." Staff's initial brief, p. 22 (quoting MCL 460.1179). However, the Staff stated that the sale of the REC:

> would result in the usage otherwise covered by that generation to ostensibly require RECs to be retired in proportion with the clean or renewable requirement associated with that same usage. [Act 235] includes neither DG customer usage behind the meter covered by the DG generation *or* the outflow associated the DG generation in the amount of usage necessary to cover with clean and renewable generation.

Staff's initial brief, p. 23 (emphasis in original). The Staff also contended that although DG resources are renewable by definition, it appears that the Legislature, in enacting Act 235, intended that Sections 73 and 79 would harmonize by recognizing that DG is already clean and renewable and should not be included in the usage that the company must cover with clean or renewable energy. According to the Staff:

> [i]f a DG customer does not seek to have RECs granted for its generation, the RECs that would otherwise exist are effectively retired to cover the generation. If a DG customer does seek to have RECs granted, the ownership stays with the customer so they can be retired in order to maintain the renewable status of the generation. Therefore, the appropriateness of participation in the DG program includes the exclusion of usage associated with that generation from the clean and renewable standard. To allow an entity other than the customer to own any RECs associated with DG generation would undermine both the program itself and the clean and renewable standards; therefore, the Legislature prevented this from occurring. Notably, the law is silent on the disposition of any such RECs. However, only by assuming their retirement by the owner can the various portions of the law be read so as not to produce an unreasonable result and should therefore be read that way.

Id., p. 24.

The Staff also noted that MCL 460.1173(2) limits a DG customer's generation capacity up to 110% of the customer's electricity consumption for the previous 12 months. *See*, *id*., p. 25. The Staff explained that this section limits a DG customer's production to a reasonable projection of the customer's usage; accordingly, there is no excess production that would need to be covered by the clean and renewable energy standards in Section 79 of Act 235 and, therefore, this issue is not addressed in the statute.

Consumers disagreed with GLREA that the purchase of DG RECs will support REC compliance under Act 235. The company asserted that:

> [b]ecause the average number of megawatt hours of electricity sold by the electric provider reflects the distributed generation that is utilized by the customer and the distributed generation outflow further reduces the sales upon which the Company must comply, the RECs provide no additional value to the Company in achieving RPS compliance as the DG, and the associated RECs, should not be double counted.

2 Tr 122.

In response to GLREA's recommendation that the Commission require Consumers to purchase RECs from DG and PURPA projects prior to purchasing RECs from out of state, the company noted that it already has contracts to purchase certain PURPA RECs. Furthermore, the company argued that GLREA's recommendation to curtail Consumers' ability to purchase RECs from out-of-state providers could result in dormant commerce clause concerns. In any event, the company contended that this issue is not ripe for consideration in this case because it will be addressed in Consumers' VGP filing in the fall of 2025. *See*, Consumers' initial brief, p. 8.

GLREA disagreed with Consumers and the Staff that DG RECs cannot be used for RPS compliance. GLREA stated that "the Commission has already ordered that RECs purchased from DG customers can be used for non-contracted VGP customers in a DTE [Electric Company (DTE Electric)] case," and that the August 22, 2024 order in Case No. U-21374 (August 22 order) “directed [Consumers] to conduct an outreach session on buying RECs from DG customers. It would hardly make sense for the Commission to order the Company to hold an outreach session on buying something for which the Company had no legal use.” GLREA’s initial brief, p. 19 (citing the August 24, 2024 order in Case No. U-21172). In response to the Staff’s argument that if the Commission approves the use of DG RECs, it should only be outflow RECs, GLREA stated “[w]e agree on that much; it was never our intention to suggest the sale of RECs from DG customer self-consumption; our proposal is concerned with selling RECs from DG *outflow*.” *Id*., p. 20 (emphasis in original).

GLREA agreed with the Staff that a REC is the renewable attribute of energy generated from a renewable resource and that, pursuant to Act 235, the DG customer owns any RECs generated on the customer’s site. GLREA stated that:

> given that the Company is buying DG outflow *energy* without buying the related RECs (which the law makes clear are owned by the customer) the outflow that the Company is buying is not renewable. Participation in the DG program requires renewable generation, but apparently not the sale of renewable energy. To get renewable energy, the Company would need to purchase the RECs as well. This is one reason that we believe Company witness Johnston is incorrect in his assertion that the subtraction of DG outflow from the Company’s load, and buying the REC, would constitute a double-count. Because the law makes it clear that the customer still owns the REC it has not been “counted”. The subtraction from the Company’s load must represent something else to the legislature. We assert that the subtraction of DG outflow can reasonably be considered an incentive for regulated electric utilities to support the expansion of their DG programs.

Id., pp. 20-21 (emphasis in original). In addition, GLREA asserted that prohibiting DG customers from selling their RECs would be a taking of private property that violates the United States (U.S.) Constitution and the Michigan Constitution. Therefore, GLREA requested that the Commission determine in this proceeding that DG customers may sell the RECs from their outflow and that Consumers may use any RECs it purchases in its non-contracted VGP offering, in its contracted RECs offering, or for RPS compliance.

The ALJ found GLREA's argument somewhat persuasive. However, he agreed with Consumers that "issues related to the structure or operation of the VGP program, like the treatment of RECs from DG customers, should be addressed in the Company's VGP filing." PFD, p. 11. In addition, he noted that in Case No. U-21662, DTE Electric and the Staff suggested that this same issue should be resolved in the VGP filing; the ALJ in that case agreed. Accordingly, the ALJ recommended that the parties revisit this issue in Consumers' upcoming VGP filing.

MEIU excepts, asserting that the ALJ did not consider MEIU's briefing on this issue. MEIU acknowledges that, in this case, it did not provide testimony on this issue but has "submitted extensive testimony and briefing (and at least one petition for rehearing) on the issue in Case Nos. U-21172 (DTE [Electric]'s 2022 VGP case), U-21374 (Consumers' 2022 VGP case), and U-21375 (DTE [Electric]'s 2024 VGP case)." MEIU's exceptions, p. 9. MEIU notes that, in this case, it responded to the Staff's arguments in reply briefing. MEIU states that, "[a]lthough [it does] not disagree with the PFD's recommendation to leave the issue for resolution in Consumers' upcoming VGP proceeding, to the extent that the Commission takes it up here, it should do so with the aid of MEIU's reply briefing." *Id*.

In exceptions, GLREA reiterates that the purchase of RECs from DG customers is consistent with Act 235 and constitutional law. *See*, GLREA's exceptions, pp. 10-18. GLREA again disagrees with the Staff that if DG RECs are purchased and used by the utility, the RECs are double-counted. *See*, *id*., pp. 19-21. Further, GLREA requests that the Commission reject the ALJ's recommendation that this issue be addressed in Consumers' VGP filing in the fall of 2025. Rather, GLREA states, "[a] clear declaration that DG outflow RECs may be purchased and used for RPS compliance is clearly within the scope of this proceeding, as it would provide a new source of RECs for compliance. GLREA also proposes that the Commission order the Company to include, in its VGP filling this fall, standard contract language for purchase of DG outflow RECs." *Id*., p. 21. Finally, GLREA asserts that the Commission has the duty to protect DG customers and the value of their RECs and should determine that the utility must purchase RECs from DG customers.

Consumers replies, arguing that GLREA "fails to address the crux of the ALJ's determination. The [Commission] has already indicated that this issue will be addressed in the Company's [VGP] filing in the fall. Thus, this issue is not ripe for consideration in this proceeding and GLREA's argument should be rejected." Consumers' replies to exceptions, p. 2 (citing the August 22 order).

After considering the parties' arguments on this issue, the Commission finds the issue is well within the scope of the instant case and, therefore, declines to adopt the ALJ's recommendation to defer a decision on this issue to the VGP proceeding. The Commission also finds the Staff's position on this issue persuasive and that it should be adopted. As noted by the Staff, MCL 460.1028(2) specifically describes how the RPS is to be calculated; the Staff provided an equation to illustrate:

$$RPS\% = \frac{REC_{Requirement}}{Load - Load_{VGP} - DG_{Outflow}}$$

4 Tr 856. The Staff states that "[t]he only two operations that you can do to a fraction or ratio without changing the value is to add zero or multiply by one. If a utility even had the data to add the load back in, it seems as if PA 235 would not allow it as there is no provision to add load back in." 4 Tr 856. The Commission agrees that pursuant to the calculation provided by Section 28(2) of Act 235, Consumers should not purchase RECs associated with DG outflow from customers because it will reduce the amount of total renewable generation required to meet VGP and RPS compliance without simultaneously increasing the denominator with the corresponding generation

from DG outflow. This results in a form of double-counting, as argued by the Staff. Therefore, the Commission declines to adopt GLREA's position on this issue.

b. Landfill Gas Renewable Energy Credits

MEC/NRDC noted that according to Consumers' amended REP, the company plans to use RECs from landfill-gas-fueled generation to comply with the RPS standard. MEC/NRDC stated that pursuant to Section 11(*i*)(i) of Act 235, a utility may meet the renewable energy standards set forth in Section 28 of Act 235 by utilizing RECs from a "renewable energy system," which may include "[a] landfill gas recovery and electricity generation facility located in a landfill whose operator employs best practices for methane gas collection and control and emissions monitoring, as determined by the department of environment, Great Lakes, and energy [(EGLE)]." 2 Tr 400 (quoting MCL 460.1011(*i*)(i)); *see also*, MCL 460.1028. MEC/NRDC contended that Consumers failed to present evidence demonstrating that the proposed landfill-gas-fueled generation RECs comply with the standards in Section 11(*i*)(i) of Act 235 requiring the landfill operator to employ best practices for methane gas collection, control, and emissions monitoring. Accordingly, MEC/NRDC requested that "the Commission adopt practices in the administration of the MiRECS [Michigan Renewable Energy Certification] system that ensure that all landfill gas generation RECs registered in that system, and thereby available for compliance with the renewable energy standard, have documented certification by [EGLE] that the landfill source follows best practices." 2 Tr 401.

Consumers responded that it had "already entered contracts for landfill generation prior to the effective date of [Act 235]." 2 Tr 251. Consumers noted that these contracts are for landfill-gas-fueled generation that comprises approximately 3% of the company's RECs. Consumers asserted that any new landfill-gas-fueled generation contracts will include a provision requiring the facility to comply with the standards set forth in Section 11(*i*)(i) of Act 235. However, Consumers requested that "it be provided with the opportunity to collaborate with landfill site owners and to consider the options available under current contracts before the Commission determines that the RECs associated with those facilities should not be used for REC compliance." Consumers' initial brief, pp. 9-10. The company stated that if it is unable to use the RECs from its current landfill-gas-fueled generation contracts, Consumers may not be able to meet the RPS targets.

Although MEC/NRDC acknowledged Consumers' concerns, MEC/NRDC argued that the company's claims that it may not meet the RPS targets may be overstated. MEC/NRDC asserted that:

> [f]irst, as noted above, the landfill gas RECs only comprise 3% of the Company's REC portfolio in 2025 – after that, they drop to 2%, then 1%, and then [to] a negligible amount. Second, recognizing that Consumers has not yet determined how these provisions would operate, it appears that four of the Company's seven landfill gas contracts have change in law provisions that could facilitate the Company's efforts to work with landfill owners to ensure compliance with the new standards.

MEC/NRDC's initial brief, p. 41 (citing Exhibits A-34 and MEC-29). In addition, MEC/NRDC contended that Act 235 has no exception for existing contracts that do not contain a change-in-law provision. Therefore, MEC/NRDC requested that the Commission determine "that power purchased from facilities that do not meet the new standards may not be considered renewable energy eligible for REC accrual, and that costs for such purchases may be considered imprudent and disallowed in future REP reconciliation cases." MEC/NRDC's initial brief, p. 42.

Consumers did not dispute MEC/NRDC's assertion that Act 235 now requires landfill-gas-fueled generation facilities to "employ[] best practices for methane gas collection and control and emissions monitoring, as determined by the department of environment, Great Lakes, and energy." Consumers' reply brief, p. 4 (quoting MCL 460.1011(*i*)(i)). However, the company stated that "there has been no [Commission] or other guidance as to the process for making this 'best practices' determination." *Id*. The company reiterated its request that the Commission provide Consumers time to consider options under its current contracts with landfill-gas-fueled generation facilities before the RECs are excluded or the costs are disallowed in a reconciliation proceeding.

In response, MEC/NRDC asserted that Act 235 does not provide "an indefinite grace period," but "[t]o the extent that Consumers needs a window of time to deal with its landfill contract counterparties, that time is available between now and the reconciliation cases – which is when MEC-NRDC asked the Commission to act on this issue." MEC/NRDC's reply brief, p. 2.

The ALJ agreed with MEC/NRDC that Act 235 requires RECs from landfill-gas-fueled generation to be purchased from facilities that employ best practices as determined by EGLE. The ALJ found Consumers' "request for a grace period unavailing and further notes that the Company should have been on notice since the passage of Act 235 in 2023 that such requirements were going to be necessary in order for Landfill Gas RECs to be used to meet the RPS." PFD, pp. 13-14. Thus, the ALJ recommended that the Commission find that power purchased from landfill-gas-fueled generation facilities that do not employ best practices certified by EGLE is not eligible for RECs, that the purchase of such power may be found to be imprudent, and that the costs may be disallowed in an REP reconciliation case.

Consumers excepts, arguing that "(1) additional guidance is needed to determine how to comply with the new statutory requirement and (2) cost recovery for these PPAs [power purchase agreements] has been previously approved by the Commission pursuant to various statutory provisions." Consumers' exceptions, p. 4. The company asserts that it is not clear from the statutory language what constitutes "best practices," what type of "certification" is required to comply with "best practices," whether EGLE would provide the certification, if a statement from the landfill gas operator would be equivalent to a certification, and, if so, what the statement should include. *See*, *id*.; *see also*, MCL 460.1011(*i*)(i).

Additionally, Consumers contends that it pays for and receives energy and/or capacity pursuant to the terms of existing landfill gas PPAs. The company states that "[e]ven if it is eventually determined that RECs are not available for use in the RE [renewable energy] Plan from any of these PPAs, that does not invalidate the previously approved agreements and does not provide for a disallowance of the energy and capacity costs paid under those agreements." Consumers' exceptions, p. 5.

MEC/NRDC reply that "[w]hile [it does] not disagree that guidance regarding the required certification for landfill gas operators would be beneficial, the law no longer provides for landfill gas RECs sourced from facilities other than those that use best practices for methane collection and control and emissions monitoring." MEC/NRDC's replies to exceptions, p. 2. Accordingly, MEC/NRDC request that the Commission adopt the ALJ's recommendation.

The Commission finds that to meet the REC standard under Act 235, an electric provider may obtain RECs from several sources, including a "renewable energy system." *See*, MCL 460.1028(5). According to Section 11(*i*)(i) of Act 235, a landfill gas recovery facility is a "renewable energy system" if it "employs best practices for methane gas collection and control and emissions monitoring, as determined by the department of environment, Great Lakes, and energy." MCL 460.1011(*i*)(i). As stated in Section 11(*i*)(i) of Act 235, "best practices" are to be determined by EGLE. The Commission encourages the parties to work with EGLE to develop best practices for landfill gas recovery facilities. In addition, the Commission expects that, to qualify for the REC standard under Act 235, any new landfill gas PPAs, or renewals of existing landfill gas PPAs, must be executed with a landfill gas facility that employs best practices as defined by EGLE.

The Commission agrees with Consumers that, prior to the enactment of Act 235, several landfill gas PPAs and the associated cost recovery were approved by the Commission in previous cases. The Commission also agrees with the company that determining REC eligibility in an REP for landfill-gas-fueled generation does not affect the recovery of energy and capacity costs paid by Consumers under those landfill gas PPAs. Rather, the determination of the reasonableness and prudence of the energy and capacity costs for the landfill gas PPAs would occur in a power supply cost recovery (PSCR) proceeding.

c. Incentive Renewable Energy Credits

i. On-Peak and Off-Peak Incentive Renewable Energy Credits

MEC/NRDC noted that Section 39(2) of Act 235 "requires the granting of certain quantities of incentive RECs under five different circumstances, including a '1/5 renewable energy credit for each megawatt hour of electricity generated from a renewable energy system, other than wind, at peak demand time as determined by the commission' under subsection (b)." MEC/NRDC's initial brief, pp. 20-21 (quoting MCL 460.1039(2)(b)). MEC/NRDC stated that:

> Consumers has calculated incentive RECs for electricity generated from a renewable energy system, other than wind, at peak demand time using on-peak hours as previously defined by MISO [Midcontinent Independent System Operator, Inc.] -0600 through 2200 EST [Eastern Standard Time], excepting weekends and some holidays. MCL 460.1039(2)(b) states that peak demand time is to be determined by the Commission. The Commission referenced this definition in its December 4, 2008 temporary order in Case No. U-15800 [(Temporary Order)].

2 Tr 432 (citing Exhibit MEC-9) (footnotes omitted).

MEC/NRDC asserted that the temporary order in Case No. U-15800 is now 16 years old and the grid has significantly changed, including the addition of intermittent renewables, which will continue to be added to MISO Zone 7. MEC/NRDC stated that "[w]hile avoiding any legal interpretation of the governing law, it is reasonable to assume that the intention of providing incentive RECs for non-wind renewable generation technology was to support the build-out of generation that would benefit the grid in its most constrained hours. The current definition does not do this." 2 Tr 432. MEC/NRDC requested that the Commission reconsider the hours of peak demand for purposes of calculating incentive credits pursuant to Section 39(2)(b) of Act 235.

Consumers responded that it "has no choice but to follow the Commission direction provided in its December 4, 2008 temporary order in Case No. U-15800. The Company has calculated and presented its incentive REC[s] in each of its renewable cost reconciliations since 2009 in accordance with the Commission direction." 2 Tr 106. In addition, the company disagreed with MEC/NRDC's recommendation that a change to the hours of peak demand should be made in this case. Rather, Consumers stated that any change to the peak demand time should involve other utilities and should be considered and thoroughly reviewed in an industry workgroup.

The Staff stated that "there are discussions of updating this definition within MISO," and it may "be premature to update the current definition at this time." 4 Tr 808. In addition, the Staff noted that because this definition affects all electric providers, any update to the definition should include input from all affected utilities and interested persons. The Staff recommended that "this discussion take place in a standalone workgroup or in the transfer price workgroup suggested above. However, updating this definition in advance of a potential MISO definition update may result in a need to update the definition again in the future." 4 Tr 808.

MEC/NRDC asserted that Consumers and the Staff failed to provide a compelling reason to continue using the outdated definition of "peak demand time" set forth in the Temporary Order. MEC/NRDC reiterated that the Temporary Order is 16 years old, was not intended to be permanent, should not be relied upon as precedent, is inconsistent with MISO's tariff definition, and conflicts with the language of Act 235. *See*, MEC/NRDC's initial brief, pp. 22-27.

The ALJ agreed with MEC/NRDC that the definition of "peak demand time" in the Temporary Order is outdated, but he declined to recommend that the Commission reject Consumers' calculation of incentive RECs. The ALJ stated that "it would be unreasonable to implement a new definition in this case when this is an industry-wide issue. Accordingly[,] this PFD recommends that the Commission create a workgroup to develop an updated definition of peak demand time to be used in calculating incentive RECs under subsection 39(2)(b)" of Act 235. PFD, p. 16.

MEC/NRDC excepts to the ALJ's recommendation that the Commission reject MEC/NRDC's proposal and, instead, defer the decision to a workgroup. MEC/NRDC asserts that "doing so would mean approving an incentive REC calculation based on a methodology that is not supported by substantial evidence." MEC/NRDC's exceptions, p. 2. In addition, MEC/NRDC contends that it is not necessary to involve all utilities in a discussion to define peak demand time. MEC/NRDC states that "[t]he Commission routinely establishes precedent in contested cases involving one utility that it later applies in cases involving other utilities. Nothing requires all utilities governed by a statute to be parties to any case in which that statute is interpreted and applied." *Id*., p. 3 (citing the July 2, 2024 order in Case No. U-21461, pp. 84-87). Moreover, MEC/NRDC argues that it is unclear when or how the proposed workgroup will resolve this issue. Therefore, MEC/NRDC asserts that the Commission should adopt MEC/NRDC's proposed definition because it "is reasonable and well aligned with the statute's purpose. No party presented evidence to the contrary, nor did any party recommend a better or even different definition." *Id*., p. 4.

In reply, Consumers states that its calculation of incentive RECs is supported by substantial evidence and that the definition of on-peak hours is being considered by the workgroup established in Case No. U-21662. The company notes that although MEC/NRDC expressed concern about the certainty of a decision in the workgroup:

> the Commission ordered Staff to "submit to the Commission a final report no later than September 1, 2025." The Commission will then determine how to proceed regarding this issue. In the meantime, the Commission should not make any determinations in this case regarding on-peak incentive RECs that would disrupt the workgroup process that is already ongoing, and the Commission should reject MEC's proposal to adopt its definition of "peak demand time" in this case.

Consumers' replies to exceptions, p. 4 (quoting the May 15, 2025 order in Case No. U-21662 (May 15 order), p. 4; citing the August 7, 2025 order in Case No. U-21662).

The Commission notes that in the May 15 order, it directed the Staff to, among other things, "convene a workgroup to revise the definition of on-peak hours for the determination of incentive renewable energy credits no later than June 7, 2025, with a report to be filed with the Commission by September 1, 2025." May 15 order, p. 4. The Staff hosted an online symposium on June 5, 2025, at which the Staff and a representative from 5 Lakes Energy provided presentations, and numerous interested persons were in attendance. The Commission notes that the Staff and interested persons explored the issue of "peak demand hours" for incentive RECs, and that the required report was timely filed in the docket for Case No. U-15800 on August 29, 2025. *See*, filing #U-15800-0066 in Case No. U-15800. With the final report now filed, the Commission expects to provide guidance for all affected utilities on this issue in the near future.

In the immediate case, the Commission agrees with Consumers that the company is required to comply with the directives of the Temporary Order. Therefore, the Commission finds that Consumers' proposed incentive RECs, as calculated using the "peak demand hours" set forth in the Temporary Order, are approved for 2023. However, until the Commission receives the final report to be issued on September 1, 2025, in Case No. U-15800, and determines whether any adjustments should be made to how incentive RECs are calculated, the Commission declines to approve Consumers' incentive RECs for 2024-2045.

ii. Off-Peak Generation for Storage Incentive Renewable Energy Credits

MEC/NRDC also objected to Consumers' calculation of incentive RECs for electricity generated from a renewable energy system during off-peak hours, stored in an energy storage system or hydroelectric pumped storage facility, i.e., the Ludington Pumped Storage Plant (Ludington), and then used during peak hours. MEC/NRDC noted that in the Temporary Order, "the Commission approved a method for calculating the storage incentive REC based on the lesser of the renewable energy generated during off-peak hours and the energy used to charge the storage system:

> Advanced Electric Storage Technologies or Hydro Electric Pumped Storage Facilities.
>
> Pursuant to Section 39(2)(c) [of Act 235], the Michigan Incentive REC is determined to be the renewable and/or advanced cleaner energy that is generated during the off-peak period and used to charge the Advanced Electric Storage Technology, or fill the Pumped Storage Facility on an hourly basis. The determination of this value for each off-peak hour shall be the lesser of (1) the sum of the net renewable and advanced cleaner energy that is generated during each off-peak hour, or (2) the energy used to charge the Advanced Electric Storage Technology or fill the Pumped Storage Facility during each off-peak hour.

MEC/NRDC's initial brief, p. 29-30 (quoting Temporary Order, p. 28). MEC/NRDC asserted that the method in the Temporary Order fails to accurately estimate the amount of renewable energy that is used to fill the storage reservoirs. According to MEC/NRDC:

> [w]hen Ludington pumps water to fill the reservoirs, "that power is drawn from the MISO grid and adds to the load that MISO serves." In other words, the power needed to fill Ludington is incremental load – requiring additional generation beyond what MISO is already operating when Ludington turns on. The additional generation to fill Ludington comes from the next resource in the economic dispatch sequence. Unless renewables are being curtailed on the system at that time, the

> next generating resource to dispatch will be [sic] not be renewable – it will be a conventional generating plant with marginal costs. Hence, it is unreasonable to assume that all renewable generation operating at the time of pumping is used to pump Ludington. Instead, the Commission should determine that electricity generated from a renewable energy system during off-peak hours is stored in Ludington only when renewable resources are on the margin when Ludington is pumping, and otherwise would have been curtailed if Ludington was not pumping.

MEC/NRDC's initial brief, p. 31 (quoting 4 Tr 435). MEC/NRDC stated that if the Commission were to adopt its recommendation, Consumers' incentive RECs will need to be recalculated and, as a result, the amount of incentive RECs will be materially reduced.

Consumers disagreed with MEC/NRDC, stating that:

> [r]egardless of whether the marginal resource is renewables, power flows in the path of least resistance and unless the marginal resource is located adjacent to the Ludington Pumped Storage Facility, it is unlikely that it is serving the electric load instead of renewables. The fact of the matter is that the Company's Lake Winds Energy Park is in Ludington and, when it generates and the reservoir is being filled, it is likely the source of that electric power.

2 Tr 106. In addition, the company asserted that it is not reasonable to assume that the pumping load at Ludington is exclusively served by marginal market resources. Consumers averred that, for Ludington, the company bids the pumping load in the day-ahead submittal and receives almost the same locational marginal price that other load sources receive.

Noting that the electric energy that serves the pumping load at Ludington is not tracked, MEC/NRDC argued that it cannot be definitively determined that the facility is being charged by renewable resources. MEC/NRDC stated that Section 39(c) of Act 235 "requires that the incentive RECs 'shall be calculated based on the number of megawatt hours of renewable energy used to charge the energy storage system or fill the pumped storage facility . . . [.]' If Consumers does not know how many megawatt hours that is, there is no substantial evidence to support the company continuing to claim incentive RECs using the current calculation." MEC/NRDC's initial brief, p. 33 (quoting MCL 460.1039(2)(c)).

MEC/NRDC also asserted that in the settlement agreement approved by the May 15 order, the parties agreed that the Commission should consider revising the directives in the Temporary Order concerning incentive RECs related to energy storage systems and hydroelectric pumped storage facilities. MEC/NRDC noted that "the Commission did not expressly address the settlement term in its Order approving the settlement. MEC-NRDC believe the omission may have been an oversight . . . ." MEC/NRDC's initial brief, p. 34.

The ALJ acknowledged MEC/NRDC's argument on this issue, but:

> recognize[d] that Ludington is co-owned by Consumers and DTE Electric and, as such, any resolution of the issue of incentive RECs association with that facility should be applicable to both utilities. Accordingly, and consistent with this PFD's determination on subsection 39(2)(b) [of Act 235] and with the settlement agreement in Case No. U-21662, this PFD recommends that this issue be addressed in an industry-wide workgroup.

PFD, p. 19.

MEC/NRDC excepts, reiterating that Consumers failed to demonstrate that the calculation of storage incentive RECs is reasonable. In addition, MEC/NRDC disputes the ALJ's determination that the settlement agreement in Case No. U-21662 recommended a workgroup for storage incentive RECs. MEC/NRDC notes that the August 7, 2025 order in Case No. U-21662 appeared to recommend that this issue be discussed in a transfer price and peak demand symposium. According to MEC/NRDC, the symposium is complete and "no decision or recommendation has been made on this issue. It is unclear at this point what the path is now to a decision on this issue via the workgroup process." MEC/NRDC's exceptions, p. 9 (citing the August 1, 2025 Draft Staff Report in Case No. U-15800). Therefore, MEC/NRDC request that the Commission direct Consumers to rework the method for calculating storage incentive RECs consistent with MEC/NRDC's recommendations.

As noted by the ALJ, the Ludington Pumped Storage Plant is jointly owned by Consumers and DTE Electric. The Commission finds that it would be imprudent to make a determination regarding incentive RECs in this case, which would also affect DTE Electric. This issue was discussed in the workgroup ordered by the May 15 order and the final report filed on August 29, 2025, in Case No. U-15800. As noted above, with the final report now filed, the Commission expects to provide guidance to all affected utilities on this issue in the near future.

d. Renewable Energy Credit Market Purchases (Renewable Energy Credit Only Contracts)

Consumers stated that it plans to meet RPS targets with "RECs provided from market purchases according to Act 235, Section 28(5)(c) permitting procurement of not more than 5% of RECs to comply with the renewable energy standard. This 5% RECs provision cannot be used to comply with the renewable energy standard after 2035." 2 Tr 243.

MEC/NRDC objected to Consumers' RECs purchased on the open market, asserting that although these RECs constitute a small part of the company's portfolio, they are expensive. MEC/NRDC noted that:

> [f]rom 2026 through 2035, Consumers plans to purchase 7,013,979 RECs at a cost of $14.03 million at a projected cost of $2 per REC. This compares to an average REC cost from Consumers-owned or PPA-purchased RECs of $.35; this is over a five-fold difference in price between Consumers' projected price for market-purchased RECs and its projected price for other REC sources.

2 Tr 419 (citing Exhibit A-38). MEC/NRDC also noted that DTE Energy (DTE) assumes a higher rate for its market purchases of RECs: "[f]or project RECs purchased prior to 2030, DTE assumes a cost of $3/REC, with $5/REC assumed in all years from 2030 and beyond." 2 Tr 419 (citing Exhibit MEC-5). MEC/NRDC stated that DTE expects the Midwest REC market to tighten because there will be greater obligations under the RPS standards in Michigan, Minnesota, and Illinois in the next 15 years. MEC/NRDC contended that, if Consumers were to "[use] the same

assumptions as DTE, Consumers would need to spend $33.07 million on the same number of RECs increasing their market-purchased REC, to other REC cost ratio to over 13 to 1." 2 Tr 419.

In addition, MEC/NRDC asserted that market-purchased RECs are not necessary for Consumers to comply with the renewable energy standard from the present year to 2035. MEC/NRDC stated that, according to Consumers, the company "expects to build a REC balance of 12.4 million RECs by 2045. This is more than the total number of RECs purchased at market prices between 2026 and 2034." 2 Tr 421 (footnote omitted). Therefore, MEC/NRDC requested that Consumers be prohibited from preemptively purchasing, or planning to purchase, open-market RECs; rather, the open-market RECs should only be purchased in the event that Consumers has a short-term risk of not complying with the RPS. However, in the event the Commission approves Consumers' purchase of open-market RECs, MEC/NRDC recommended that the Commission condition the approval on the RECs being Green-e® certified.[1] *See*, 2 Tr 420.

Consumers responded that it is unclear how MEC/NRDC calculated the average cost of $0.35 per REC for PPAs but noted that MEC/NRDC appears to reference Exhibit A-38. The company stated that, for the REC costs proposed in Exhibit A-38, it "does not allocate any expense for RECs generated from Company-owned renewable energy resources or a cost for incentive RECs as part of the Average REC Cost calculation in Exhibit A-38 (CCO-6)." 2 Tr 248-249. In any event, Consumers asserted that Section 28(5)(c) of Act 235 permits:

> electric providers to meet the REC Standard with RECs obtained from purchasing RECs without the associated renewable energy or capacity, with the only limitation being that the RECs (i) must be "produced within the territory of the regional transmission organization of which the electric provider is a member," (ii) must not

[1] A REC is created for each MWh of renewable electricity generated by wind, solar, biomass, geothermal, and certain hydropower sources and then delivered to the power grid. Green-e® is an independent consumer protection program that tracks, accounts for, and certifies the environmental benefits of RECs and verifies that the electricity was produced without burning fossil fuels.

> "exceed 5% of an electric provider's [RECs] annually used to comply with the renewable energy standard," and (iii) cannot be used to comply with the REC Standard after 2035. Accordingly, the Company included these market purchases of RECs as part of its plan to meet the renewable energy targets consistent with the limitation in MCL 460.1028(5)(c).

Consumers' initial brief, p. 12 (citing 2 Tr 243).

In addition, the company disagreed with MEC/NRDC that open-market RECs should only be used to remedy short-term risk of non-compliance with the REC portfolio standard. Consumers contended that there are other risks identified in the company's REP, "such as siting, tariffs, interconnection, sales uncertainty, price uncertainty, and tax credits. The Company is planning for these REC-only purchases as a cost-effective way to ensure REC compliance is achieved." 2 Tr 250. Furthermore, Consumers asserted that it is not necessary to require that the open-market RECs have Green-e® certification. The company explained that MIRECS is a "sophisticated tracking system" that "protect[s] the integrity of the RECs as well as prevent[s] any double counting." 2 Tr 249.

MEC/NRDC acknowledged Consumers' testimony that it does not allocate any expense for RECs generated from company-owned renewable energy resources or the cost for incentive RECs as part of its Average REC cost calculation and stated that, based on this information, MEC/NRDC's calculated average cost of $0.35 per REC for PPAs may be inaccurate. However, MEC/NRDC maintained that open-market purchased RECs "are still far too expensive for the value they provide, which, for ratepayers is essentially zero – market-purchased REC[s] simply allow Consumers to buy compliance for itself with no associated renewable energy or capacity for its customers." MEC/NRDC's initial brief, p. 18.

In response to Consumers' claim that open-market purchased RECs do not need to be Green-e® certified because of the MIRECS system, MEC/NRDC asserted that REC tracking is not the only benefit of Green-e® certification; rather, the certification "also ensures quality and support for new renewable energy generation." *Id*. (citing 2 Tr 420). MEC/NRDC also disputed the company's assertion that the purchase of open-market RECs mitigates other risks in Consumers' REP and provides flexibility to build a larger REC bank. According to MEC/NRDC, "there are better ways to reduce the risk Consumers says it is concerned about – for example, it can procure more wind generation sooner and use PPAs for both in- and out-of-state wind . . . ." MEC/NRDC's initial brief, p. 18.

The ALJ noted that Section 28(5)(c) of Act 235 "explicitly allows electric providers to meet up to 5% of the RPS requirements through 2035 by purchasing market RECs. If the Legislature intended to place more or different restrictions on the acquisition of these RECs, as MEC-NRDC recommends, it would have done so in the Act." PFD, p. 22. However, the ALJ stated that Consumers has an obligation to demonstrate in its REP reconciliation proceeding that open-market purchases of RECs are reasonable, prudent, and necessary to comply with the RPS. Furthermore, the ALJ noted that Section 28(6) of Act 235 requires the Commission to review REC-only contracts. Therefore, the ALJ asserted that "there are appropriate mechanisms to ensure that the use of market RECs is warranted and is reasonable and prudent." PFD, p. 22. The ALJ recommended that the Commission decline to approve MEC/NRDC's amendments to Consumers' open-market REC purchase proposal.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted. The Commission also finds Consumers' argument persuasive that it is not necessary to require that the open-market RECs have Green-e® certification. MIRECS includes the unique serial numbers of the RECs, transaction data, complete audits, and exclusive tracking, which is sufficient to ensure quality and prevent the risk of double-counting.

2. Resource Additions

a. Purchased and Company-Owned Solar Energy Resources

GLREA expressed concern that the transmission-connected solar facilities in Consumers' REP would be required to go through the MISO interconnect process, which may result in build schedule delays and possible non-compliance with statutory deadlines for the RPS. GLREA asserted that:

> [b]ecause the distribution system cannot host generating facilities as large as those in the current build plan, this approach would also require soliciting smaller projects. This reduces schedule risks in two additional ways: it means that the delay of any single project has less impact, and smaller facilities are less likely to encounter local opposition, reducing siting risks. In some cases, the Company may own sufficient land to support a smaller solar facility, eliminating the requirement to acquire land rights. Smaller solar facilities may also mitigate the transformer supply risk by using smaller transformers.

4 Tr 579. In addition, GLREA contended that connecting generation facilities to the distribution grid has the benefit of avoiding the cost of transmission, energy losses in transmission, and line losses. Furthermore, GLREA stated that "[t]argeting the location of the installation to connect at a substation that is under stress may also allow the delay or avoidance of an expensive substation upgrade." 4 Tr 579. Therefore, GLREA recommended that the Commission direct Consumers to, in its next solicitation, "include an option for a distribution-connected pilot, with a list of connection points in which the addition of generation would support the distribution grid, and the capacity of generation each interconnection point could support." 4 Tr 581. In the alternative, GLREA requested that the Commission direct the company to provide a contract for smaller, under 5 megawatts (MW) distribution-connected, solar facilities that are priced based on recent company solicitations, similar to those set forth in DTE Electric's recent REP, Case No. U-21662.

MEC/NRDC stated that it supports "competitive procurement of renewables on a non-discriminatory basis, in order to obtain the best value for utility customers and overcome the bias toward utility-owned resources that is inherent in rate-of-return utility regulation." 2 Tr 409. However, MEC/NRDC noted that, according to Consumers, the risks for developing renewable energy systems that comply with the RPS include the MISO interconnection queue and siting of the renewable energy systems. In MEC/NRDC's opinion, the impediment of the MISO interconnection queue can be avoided by building small projects that are interconnected with the company's distribution system. Additionally, MEC/NRDC asserted that larger projects usually encounter "greater siting opposition within a host community." 2 Tr 410. Therefore, MEC/NRDC recommended that the Commission allow Consumers, pursuant to MCL 460.1028(6), to use standard-offer contracts for small projects that may be developed without participating in the competitive bidding process, such as build-and-transfer agreements (BTAs) and PPAs. MEC/NRDC "recommend[ed] that the prices offered for such standing offer contracts be calibrated from time-to-time based on the prices of projects selected in Consumers['] . . . competitive bidding processes but adjusted for differences in line losses between the project location and the physical load served by the project versus line losses between large projects and the physical load they serve." 2 Tr 412.

MEIU contended that the Commission should allow mid-size solar projects, specifically in settled areas, of up to 10% of total incremental solar resource additions over the relevant three-year period. MEIU explained that:

> [m]id-size projects are large enough to leverage economies of scale enjoyed by utility-scale systems, so they can be developed at costs that are highly competitive. Unlike larger-scale resources, however, and not unlike behind-the-meter resources, mid-size projects can be flexibly located and can provide distributed benefits including avoided transmission line losses, deferral of distribution infrastructure upgrades, and increased system resilience. Because mid-size projects have an

> opportunity to interconnect to medium-voltage (MV) distribution systems, the interconnection process also has the potential to be more streamlined and less expensive, as system impact studies for distribution-level projects can be simpler and more straightforward than similar studies for utility-scale projects. Mid-size projects can also take advantage of the expanded federal Investment Tax Credit ("ITC") for interconnection costs for smaller-output facilities (<5 MW), further lowering costs.

4 Tr 658-659 (footnotes omitted).

The Staff stated that it is "intrigued by [MEIU's] discussion asserting that smaller scale projects can be cost effective due to avoidance of transmission interconnection costs. As such, Staff could be supportive of a small-scale solar program or Community Solar Program (both 5 MW and under) standard offer program that resulted in reasonable costs to the Company." 4 Tr 816. However, the Staff expressed concern that smaller projects are less cost competitive and require subsidization. The Staff asserted that:

> [o]ne potential measure of the reasonableness of such costs could be that they be compensated through a tariff equal to the levelized cost of a selected Company-owned renewable project or PPA in the Company's most recent RFP [request for proposal] solicitation, and in the case of a Community Solar program, the tariff rate would subtract out the costs to establish participant bill crediting. This would enable a test of the theory that small distribution voltage interconnections provide cost savings over transmission interconnections. Additionally, any Community Solar program should count towards the 10% distributed generation (DG) cap as this program should be designed in a manner that provides a DG option for those that are unable to install DG themselves such as renters, wooded lots, economics, etc.

4 Tr 816.

Consumers contended that although its modeling assumes a levelized cost of energy (LCOE) based on transmission-connected facilities, "[t]he Company intends to continue to allow distribution connected facilities in its annual RFPs and will continue to consider them on the same basis as transmission connected projects. To the extent that distribution connected facilities can provide timely and economic renewable energy resources, they will be considered for selection."

2 Tr 359. Consumers noted that, historically, the smallest size project that could participate in the company's RFP is 0.15 MW alternating current (MWac) for PURPA-qualified facilities and 1 MWac for non-PURPA-qualified facilities. The company asserted that it "has signed multiple PURPA contracts for resources less than 5 MW in each of the last three years." 2 Tr 362.

Consumers disagreed with MEIU's recommendation that the Commission allow a procurement carveout of up to 10% for midsize solar resources. The company stated that MEIU "appear[s] to be arguing the economic benefits of mid-size (1-5 MW) resources. Assuming this to be true, then there would be no need to create a carveout specifically for mid-size (1-5MW) resources in the Company's RFPs because these resources can participate, and based on this claim, should be economically competitive." 2 Tr 364.

Consumers acknowledged MEIU's claim that there may be non-economic benefits to mid-size projects. However, the company stated that it has not conducted system-wide detailed modeling for these projects, which would be better performed in the company's integrated resource plan (IRP). In addition, Consumers contended that a 10% carveout for mid-size projects is not necessary because the company "allows distribution connected projects to bid into RFPs and utilizes distribution specific assumptions for modeling the economics of distribution projects in RFPs." 2 Tr 364.

Consumers contended that although MEIU claims that the carveout may reduce the risk for RPS non-compliance, MEIU did not consider the cost of risk avoidance. The company noted that it has not performed an RPS non-compliance risk assessment either. In any event, Consumers stated that if it "experiences significant delays or changes to its plan which impact its ability to maintain RPS compliance, the Company will assess its options for maintaining RPS compliance at that time, using more recent and relevant data than what might be provided in this case." 2 Tr 365.

GLREA noted that it would support the Staff's proposal, with one adjustment, for a small-scale solar program or community solar program (both 5 MW or smaller) standard offer program that resulted in reasonable costs to Consumers. GLREA asserted that "[i]f there is to be a tariffed standard offer, the contract price should have an adder equal to the cost of using the transmission network (the fee the Company pays to ITC [Holdings Corp.]), and an adjustment for transmission line losses. Both of these costs are directly avoided with a distribution-connected system." GLREA's initial brief, p. 14.

In response to Consumers' claim that it allows bids for distribution-connected facilities as small as 1 MWac, GLREA argued that this is insufficient. According to GLREA, Consumers' proposal "fails to recognize the cost savings of avoiding the transmission system" that are "directly financially quantifiable." *Id*., pp. 14-15. Although GLREA acknowledged that interconnection to the distribution system is not cost-free, it is more rapid, which results in cost savings. Additionally, GLREA asserted that there are non-financial benefits to distribution-connected facilities such as company control over the planning process and interconnection schedule as compared to the lengthy MISO interconnection process.

GLREA contended that distribution-connected facilities are at a disadvantage competing in the same solicitation as transmission-connected facilities, that there should be a separate solicitation, and that it be conducted as a pilot program similar to Consumers' substation-connected battery systems pilot. Furthermore, GLREA asserted that Consumers "has not provided any means for developers to know what parts of their distribution system could support a substantial solar generation facility," and requested that the company provide this information. *Id*., p. 16.

MEC/NRDC objected to Consumers' claim that it already offers an opportunity for small-size projects to participate in the RFP through PURPA. MEC/NRDC asserted that "PURPA is not an economically viable avenue for the kinds of small projects witness Jester described because it does not offer pricing that is comparable to that available in the RFPs – if the small projects had any chance of competing with large greenfield projects in the first place." MEC/NRDC's initial brief, p. 38.

The ALJ agreed with GLREA and MEC/NRDC that distribution-connected solar could provide greater benefits than transmission-connected solar and that Consumers failed to provide persuasive reasons to reject GLREA's and MEC/NRDC's proposals to facilitate smaller projects. Therefore, the ALJ:

> [r]ecommend[ed] that the Commission order that in its next solicitation, the Company include an option for a distribution-connected pilot, with a list of connection points in which the addition of solar generation would support the distribution grid, and the capacity of generation each interconnection point could support. In the alternative, the Commission could direct the Company to create a standard contract for smaller, distribution-connected solar facilities (under 5 MW), with pricing based on recent Company solicitations.

PFD, p. 27.

In exceptions, Consumers asserts that the intervenors have not demonstrated that it is necessary or reasonable to include distribution-connected solar facilities in the company's next solicitation, to create a standard contract for smaller, distribution-connected solar facilities, or that these are necessary to comply with the RPS. The company contends that "[s]maller distribution connected facilities are already able to participate in the Company's competitive solicitations and [Consumers] utilizes distribution specific assumptions for modeling the economics of distribution projects in Requests for Proposals ('RFPs')." Consumers' exceptions, p. 6. Consumers states that it will continue to allow distribution-connected facilities to participate in its annual RFPs and the company will provide the same consideration to distribution-connected projects as is offered to transmission-connected projects.

MEIU objects to the ALJ's alternative recommendation that the Commission direct Consumers to create a standard contract for smaller, distribution-connected solar facilities with pricing based on recent company solicitations. MEIU contends that the ALJ's recommendation that "pricing should be 'based on recent Company solicitations' (presumably referring to recent solicitations for large, transmission-connected projects) presents challenges to the viability of its overall recommendation." MEIU's exceptions, pp. 2-3 (quoting the PFD, p. 27). According to MEIU, smaller projects are unable to equitably compete with larger projects and, therefore, a procurement carveout or pilot is necessary to level the field. In addition, MEIU asserts that small-to-mid-size distribution-connected projects provide additional benefits that may offset the higher project costs, which are not addressed by simply providing a standard contract, as recommended by the ALJ. Thus, MEIU requests that the Commission adopt the ALJ's recommendation that Consumers include, in its next solicitation, an option for a distribution-connected pilot, as described by the ALJ. However, MEIU states that the pricing for that option should not be limited to the company's recent solicitations.

GLREA asserts that it is grateful that the ALJ recommended adoption of GLREA's distribution-connected pilot solicitation proposal. However, GLREA contends that the ALJ misstated GLREA's position, which was corrected in GLREA's brief. GLREA explains that:

> [t]he MEC-NRDC proposal is explicitly for systems under 5 MW and located in settled areas, on brown fields, and for agrivoltaics projects. GLEA's [sic] proposal does not have locational restrictions, and can apply to much larger systems, limited in size only by the engineering limit that the distribution system can support. GLREA's discovery asked the Company how large of a solar facility their distribution system could support. The Company responded that they didn't know. A third-party analysis of the Company's grid suggests 30-50 MW generation facilities can be supported by circuits of 25 to 34 kV [kilovolts]. The Company is deploying one 30 MW and one 45 MW battery storage system at its Weadock and Iosco substations (respectively), demonstrating that the Company's distribution system can support power inputs that large. Due to economies of scale, it can be expected that successful bidders in a pilot for distribution connected solar facilities

> would consist of projects in the tens of megawatts. For that reason, the solar projects which might be built under the MEC-NRDC proposal (< 5 MW) and those projects which might be built under GLREA's separate solicitation proposal, would not overlap. The two proposals are complementary and would support different projects. Both are worthy of adoption.

GLREA's exceptions, p. 24 (citing 2 Tr 412; 4 Tr 600-602). Accordingly, GLREA requests that the Commission adopt its proposal for a distribution-connected pilot solicitation and MEC/NRDC's complimentary proposal.

In response to Consumers' exceptions, MEIU asserts that the company "has still by no means established that its current procurement processes are sufficient for recognizing the full value offered by distribution-connected solar, value [sic] which, as MEIU discuss in their own Exceptions, the PFD also recognizes." MEIU's replies to exceptions, p. 2.

Consumers replies that, as set forth in the company's exceptions, the Commission should reject MEIU's and GLREA's proposals. Consumers states that "[t]here has not been a showing that these proposals are necessary or reasonable. Nor has there been a showing that these proposals are necessary to comply with the REC standard. The Company has options in place for these smaller projects and the ALJ's recommendation should be rejected." Consumers' replies to exceptions, p. 6.

In response to Consumers' claim that GLREA's proposal is unreasonable and unnecessary and does not comply with the REC standard, GLREA contends that it provided sufficient evidence on the record to support its proposal. *See*, GLREA's replies to exceptions, pp. 1-3. Additionally, GLREA continues to object to the company's claim that it allows distribution-connected facilities in its annual RFPs and that Consumers provides the same consideration to distribution-connected facilities as it does for transmission-connected projects. GLREA reiterates the arguments set forth in testimony and briefing. *See*, *id*., pp. 4-5.

The Commission respectfully declines to adopt the ALJ's recommendation. The Commission agrees with the parties that there could be cost savings with smaller scale, distribution-connected projects and, in the absence of cost savings, other benefits such as reducing the risk of RPS noncompliance and distribution system benefits—albeit at the cost of a potentially higher bid. Thus, the Commission encourages the company to find opportunities for these projects, and the associated benefits, to be considered. However, the Commission finds that there was insufficient evidence on the record to establish a reasonable and prudent standard offer and, therefore, the Commission is not directing the company to provide a particular standing offer contract. Without a more robust evidentiary record and definition and quantification of the purported benefits of these smaller scale projects, there is a risk that the company may overpay for projects when the benefits may not offset the higher costs compared to larger projects. Accordingly, the Commission finds that Consumers should ensure that enough information is provided in response to intervenor requests to allow for a robust benefit analysis, should continue to ensure that small-scale distribution-connected projects are able to participate in the competitive bidding process, and should utilize distribution-specific assumptions for modeling the economics of distribution projects in RFPs.

b. Company-Owned Wind Energy Resources

Consumers proposed to amend its REP to include up to 2,800 MW of both purchased and company-owned solar energy resources that are consistent with Consumers' IRP approved by the June 23, 2022 order in Case No. U-21090 (June 23 order) and that comply with REC requirements for 2030 and 2035. The company stated that it:

> has modeled the assets for its Amended RE Plan to all be sourced within Michigan, MISO Zone 7. However, to the extent that the Company is able to identify out of state renewable energy resources that are more financially viable than Michigan renewable energy resources due to factors such as construction cost or capacity

> factor, the Company will consider executing purchased power agreements for those assets; the Company does not intend to own out of state renewable energy resources.

2 Tr 59-60.

MEC/NRDC disagreed with Consumers' wind-build proposal for several reasons. First, MEC/NRDC contended that the company's Michigan wind-build proposal of 1,500 MW for 2032 and 800 MW for 2035 is unrealistic because "[i]n the history of wind energy development in Michigan, there has never been a year with more than 600 MW of new wind brought onto the grid." 2 Tr 422. In addition, MEC/NRDC stated that if the company delays its major wind projects until 2032 and 2035, the best wind resources in Michigan will be acquired by other utilities. Instead, MEC/NRDC recommended that Consumers "develop wind generation resources sooner and at a more even pace and by actively looking to acquire a portion of its wind energy through power purchase agreements (PPAs)." 2 Tr 423.

Second, MEC/NRDC contended that, according to Consumers, there are no favorable wind PPA contracts in Michigan and, therefore, the contracts are not worth pursuing. MEC/NRDC disagreed, stating that:

> [t]he 2023 passage of both [Act] 235 and [Public Act] 233 [of 2023 (Act 233), MCL 460.1221 *et seq*.] change [sic] would-be developers' perspective of the viability of new wind generation within Michigan. Through the enhanced RES [renewable energy standard] and new CES [clean energy standard] requirements in [Act] 235, the state has produced a clear demand signal for new renewable energy development. Developers will respond to this signal. Where the difficulty of getting siting approval for new wind generation may have once made Michigan wind development appear untenable to developers, [Act] 233's state siting pathway signals that some once unviable geographies may again be viable.

2 Tr 424-425. Thus, MEC/NRDC asserted that PPAs for wind energy in Michigan may be more available for Consumers.

Third, MEC/NRDC argued that Consumers should consider contracting for wind generation outside of MISO Zone 7. In MEC/NRDC's opinion, "[w]ind resource is very unevenly distributed geographically, and the total availability of low-cost, easily developable wind resource in MISO Zone 7 is low compared with the rest of MISO North and the overall need for wind generation to meet Michigan clean and renewable energy goals." 2 Tr 425. MEC/NRDC presented modeling data from the National Renewable Energy Laboratory's reV model showing an abundance of low-cost, developable wind resources outside MISO Zone 7. MEC/NRDC acknowledged that there are some cost risks with contracting for wind generation outside MISO Zone 7 but asserted that Consumers can manage the risks by evaluating the REP resource proposals "on the difference between levelized cost of energy and the expected basis differences of both energy and capacity in the resource location [versus] Consumers' service territory." 2 Tr 429-430.

Similar to MEC/NRDC, MEIU expressed concern that Consumers' proposal to own all 2,800 MW of wind resources "exposes ratepayers to a higher level of risk and the potential for increased cost while ignoring opportunities for third-party ownership of additional wind energy resources to support the Company's 2030 and 2035 REC compliance goals." 4 Tr 640. MEIU also asserted that following the enactment of Act 233, there has been an increase in third-party wind resource additions in Michigan that are likely to continue into the future. In addition, MEIU stated that "[t]he Company's proposal for 100% Company-ownership of the proposed wind resource additions is inconsistent with recent Commission orders that have regularly supported an approximately 50/50 split between Company-owned and third-party owned resources to fulfill utility capacity addition needs . . . ." 4 Tr 644. Furthermore, MEIU contended that Consumers' proposed ownership of all wind resources requires the company to bear all the risks of ownership: the cost of installations, operations and maintenance, tax, and capital, along with site-specific challenges, scheduling delays, and labor issues. MEIU stated that, "[b]y contrast, PPAs between the Company and third parties are most often structured in a manner that mitigates overall risk exposure for ratepayers." 4 Tr 648.

MEIU contended that if the Commission approves Consumers' proposal:

> not only would it preclude customers from enjoying cost savings that third-parties could bring to this procurement, but it would also signal a significant policy shift compared to the ownership structure for prior resource procurements, chilling future third-party interest in the State and directing the wind energy market towards a level of utility ownership it has not experienced to date.

4 Tr 651. Additionally, MEIU asserted that the company's proposal prevents ratepayers from receiving the lowest-cost, most reasonable, and prudent resources. MEIU stated that the Commission should approve an explicit 50/50 ownership split and third-party-ownership of the proposed additions and requested that Consumers follow the same competitive bidding process as it does for the company's IRP resource additions, including the use of an independent administrator (IA).

The Attorney General argued for the continued use of a 50/50 ownership split. She explained that in prior Commission proceedings, parties asserted that third-party PPAs would provide lower costs for customers; these parties relied on the Commission's February 15, 2017 Report on the Implementation of the PA 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards, which found that the weighted average cost of PPAs were consistently lower than the cost of company-owned projects. The Attorney General stated that "[b]ecause of this, parties have argued for restrictions on future ownership of renewable energy by electric utilities in order to promote and preserve the competitive market for renewable energy in the State and as a way of ultimately reducing ratepayer costs." 2 Tr 460.

The Attorney General also noted that in Consumers' IRP approved by the June 23 order, "the Company agreed that future competitive solicitations would follow existing agreements restricting Company ownership to only 50 percent of future assets." 2 Tr 459. She stated that, in this case, Consumers is proposing approximately 50% of all future VGP and REP solicitations will be provided by PPAs from third parties and 50% will be owned by the company. The Attorney General recommended that "the Commission reiterate the Company's existing commitment that only 50 percent of renewable energy resources selected through future competitive solicitations be Company-owned. This restriction is intended to limit the involvement of rate-regulated entities in the development of renewable energy facilities in the State and thus provide benefits to ratepayers from healthy competition." 2 Tr 461.

In response to MEC/NRDC, Consumers stated that:

> [a]cceleration of the acquisition of wind generation resources is dependent on cost competitive and viable projects being available that are in relatively late stages of development. The availability of those projects is scarce as indicated by recent solicitations conducted by the Company. That said, the passage of the 2023 energy legislation, including the option of siting renewable energy projects through the [Commission], has encouraged new wind development in Michigan. These projects will take several years to advance through development. The Company believes that many of these projects will be able to achieve commercial operation in the early 2030's and has therefore reflected a large increase in wind acquisition in those years. Ultimately, the Company will continue to seek wind projects through the competitive solicitation process, including within and outside of MISO Zone 7, and will acquire wind resources (through Company ownership or power purchase agreements ("PPAs")) that are price competitive.

2 Tr 233. Consumers explained that it modeled all wind resources as owned by the company because, based on the results of recent VGP solicitations, this was the worst-case scenario for the incremental cost of compliance (ICOC). However, Consumers stated that "[t]o the extent that the Company can contract for economic wind assets, its incremental cost of compliance will be reduced, all other things being equal. It is still the Company's position that it will not own wind

resources outside of the state of Michigan." 2 Tr 85-86. The company also asserted that there are advantages to company-owned wind assets, such as terminal value (additional value that would accrue for an owned asset compared to no asset value following the expiration of the PPA), the ability to re-power, and the economies of scale associated with operation of multiple renewable energy resources with standard designs.

Consumers disagreed with MEIU's proposal that the company strictly adhere to a 50/50 split between company-owned wind projects and PPAs. The company noted that in the August 22 order, the Commission found that "requiring a concrete ratio might result in inferior projects being selected just to satisfy a predetermined ratio." 2 Tr 85 (quoting August 22 order, p. 11). However, Consumers did not object to MEIU's recommendation that the company use an IA to oversee the competitive procurement process.

Although the "Staff has supported a 50/50 requirement in the past . . . and believes that there is value to competition," the Staff contended that "the Commission should continue to encourage Consumers to include the option for third-party PPAs in each renewable energy and energy storage solicitation going forward, but does not believe that it is prudent to require the Company to maintain a 50/50 portfolio in doing so." 4 Tr 809. The Staff asserted that the company should be selecting the most economical, feasible, and prudent resources to meet its requirements regardless of whether the resources are owned by Consumers or a third party.

The ALJ agreed with MEC/NRDC and MEIU that Consumers' proposal to delay acquisition of wind resources until 2032 and 2035 is not prudent. He explained that "[t]he Company's response that new wind facilities in Michigan will likely not be operational until these years ignores the current availability of out-of-state wind resources, as pointed out by MEC-NRDC." PFD, p. 35. In addition, the ALJ found Consumers' claim unpersuasive that the company's pursuit of competitively bid wind projects, in state or out of state, will result in RPS compliance. He recommended that:

> the Commission predicate its approval of the amended REP on Consumers agreement to accelerate and more evenly distribute its planned new wind development including by actively soliciting PPAs for wind generation outside MISO Zone 7. Further the Company should evaluate its RFPs on the difference between LCOE and the expected basis differences of both energy and capacity in the resource location vs Consumers' service territory and choose the most economical and valid projects that meet its requirements, as recommended by MEC-NRDC.

Id., p. 36.

Regarding the proposed 50/50 split of company-owned wind assets and PPAs, the ALJ noted that, when Act 295 was enacted in 2008, the RPS required 50% PPAs. He stated that Public Act 342 of 2016 (Act 342) repealed this requirement and, therefore, "renewables can be owned, in any proportion, by either the Company or by third-parties . . . ." *Id*. The ALJ asserted that the current proper determination is whether, on a case-by-case basis, the renewables set forth in the REP are the most reasonable, prudent, and economical, and have been informed by an RFP. He "acknowledge[d] that the Company's commitment to pursue 50% PPAs in the 2021 IRP included wind but [found] that the commitment preceded Act 235 and therefore it may no longer be reasonable considering the increased RPS targets that Consumers must meet." *Id*. The ALJ also agreed with the Staff that "that allowing third-parties to bid into and compete in RFPs coupled with the Company's continued adherence to the competitive procurement guidelines, as established in Case No[.] U-20852, should ensure cost-effective renewable procurement going forward." *Id*., p. 37. Furthermore, the ALJ recommended that the Commission adopt MEIU's proposal, with which Consumers agreed, that the company use an IA during the competitive bidding process.

Consumers does not disagree with the ALJ's recommendation that the company accelerate its planned wind development and actively solicit PPAs for wind generation outside MISO Zone 7. However, Consumers notes that the ALJ expressed doubt regarding the company's proposal and, therefore, Consumers provides additional clarification in its exceptions. The company states that:

> [w]hen moving forward with a wind project, Company witness Kenneth D. Johnston indicated that the Company would select the lowest cost resource. To the extent that a Company-owned project's Levelized Cost of Energy ("LCOE") was lower than that of a PPA + FCM (Financial Compensation Mechanism), the Company should choose the Company-owned project. Conversely, if the cost of a PPA + FCM was lower than that of a Company-owned project, the Company should select the PPA. This includes PPAs for resources outside of MISO Zone 7 - if these PPAs are more financially viable than Michigan renewable energy resources. Additionally, the Company is willing to accelerate its procurement of wind projects through competitive solicitations so long as the projects are cost competitive and viable wind projects are available in relatively late stages of development to allow for them to come online earlier than planned.

Consumers' exceptions, p. 7 (citing 2 Tr 60, 86, 233).

The Attorney General states that "[f]or the reasons identified in the Attorney General's briefing, she takes exception to the PFD's recommendation for an ownership standard other than the 50/50 standard agreed to by the Company in the U-21090 IRP settlement." Attorney General's exceptions, p. 5. She requests that the Commission reject the ALJ's recommendation on this issue.

MEIU excepts to the ALJ's finding that a strict 50/50 ownership split would be unreasonable. MEIU reiterates the arguments set forth in briefing and contends that simply allowing third parties to bid into and compete in RFPs is insufficient to encourage competition and ensure cost-effective renewable procurement. Accordingly, MEIU requests that the Commission "find that a reasonable and prudent renewable energy plan requires a 50/50 ownership split in addition to independently administered solicitations compliance with the guidelines adopted in Case No. U-20852 and to condition its approval of the Company's access to the *ex parte* approval process on achieving a 50/50 ownership split." MEIU's exceptions, p. 7.

In response to Consumers' claim that when selecting a wind project, it would select the lowest cost resource, MEIU asserts that the company's goal is worthy—in the abstract. MEIU states that "the preservation of a healthy and robust third-party competitive market—which provides alternatives to utility resource builds—is the *means* through which to ensure the *goal* that customers obtain 'the most economic value' from utility acquisitions in the aggregate and in the long run." MEIU's replies to exceptions, p. 3 (quoting Consumers' initial brief, p. 19) (emphasis in original).

Consumers reiterates the arguments set forth in testimony and briefing and restates that it "does not believe a strict 50/50 ownership split in selecting assets from its competitive solicitations is appropriate." Consumers' replies to exceptions, p. 8.

The Commission finds that the ALJ's recommendation should be adopted in part. The Commission agrees with the ALJ that it is not reasonable or prudent for Consumers to delay acquisition of 2,300 MW of wind resources until 2032 and 2035 because, as noted by MEC/NRDC, the delay may result in the company's inability to comply with the RPS. Therefore, the Commission directs Consumers to accelerate its acquisition of new wind resources, which may include actively soliciting PPAs for wind generation outside of MISO Zone 7.

The Commission agrees with the ALJ that Act 342 repealed the 50% PPA requirement for wind assets and that, pursuant to Act 235, "renewables can be owned, in any proportion, by either the Company or by third-parties . . . ." PFD, p. 36. However, the Commission agrees with the Staff that 100% company-ownership of wind resource assets is unreasonable because it precludes the benefits of healthy competition and cost-effectiveness. Therefore, the Commission adopts the ALJ's recommendation that Consumers be directed "to actively solicit third party PPAs in all its future RFPs, including those from outside Michigan, and to select the most feasible and economical projects for customers regardless of ownership." *Id*., p. 37. Put simply, the company is obligated to select the projects that are in the best interests of its customers—whether those projects are directly developed by the company, developed by a third-party under a BTA, or developed by a third-party with the electricity purchased by the utility under a PPA. This requirement, rooted in fundamental concepts of reasonableness and prudence, requires the utilization of a robust and unbiased competitive procurement process. As such, the Commission also agrees with MEIU and Consumers that the company shall use the same competitive bidding processes that it currently does for its IRP resource additions, including the use of an IA, to procure additional wind resources.

Additionally, the Commission acknowledges MEIU's concern that simply providing an opportunity for third parties to bid into RFPs is not sufficient to encourage competition and to ensure the procurement of cost-effective renewables. Accordingly, the Commission intends to expedite the review and revision process of the competitive procurement guidelines approved on September 9, 2021 in Case No. U-20852. The scale of renewable resource additions, the accelerated need for these additions, and the availability of a more lucrative FCM necessitate initiating this review to ensure that resources are procured in a fair and competitive manner, as illustrated by MEIU and Staff testimony.

The Commission respectfully declines to adopt the ALJ's recommendation that Consumers should evaluate its RFPs on the difference between LCOE and the expected basis differences of both energy and capacity in the resource location compared to Consumers' service territory, as suggested by MEC/NRDC. *See*, PFD, p. 36. Pursuant to the Revised Integrated Resource Plan Filing Requirements approved on October 27, 2022, in Case No. U-18461 (October 27 order), a utility's IRP shall include "an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the proposed resource plan over the implementation period," which shall contain, among other things, "[a] description of how, to the extent practical, the construction or investment in new resources in this state will be completed using a workforce composed of residents of this state . . . ." October 27 order, Attachment A, p. 24. Thus, the Commission finds that MEC/NRDC's proposal that the company evaluate RFPs using the difference between LCOE and the expected basis differences of both energy and capacity in the resource location compared to Consumers' service territory conflicts with the requirement in the IRP Filing Requirements that the company consider how the development or acquisition of new resources in this state "will be completed using a workforce composed of residents of this state . . . ." *Id*. Accordingly, the Commission finds that this recommendation should be rejected.

c. *Ex Parte* Approval and 140% Levelized Cost of Energy Multiplier

Consumers stated that its "modeling in this filing reflects a LCOE of $55.44/MWh for wind energy resource additions with a January 1, 2028 commercial operation date ('COD')" and an "LCOE of $70.31/MWh for solar energy resource additions with a January 1, 2028 COD." 2 Tr 60. Consumers requested that "the Commission allow the Company to receive ex parte approval for future projects for solar and wind renewable energy resources that have a LCOE which is up to 140% above the LCOEs targets" set forth above. 2 Tr 61. Consumers explained that the 140% multiplier is reasonable because it reflects risks such as developers failing to pass along tax credits, developers increasing prices in anticipation of repealed tax credits, the delay of the MISO interconnection queue, competitive solicitations priced at or below target LCOE, federal tariffs on solar panels, construction cost inflation, and increased land prices. The company stated that these risks "have resulted in fewer solar MWs at a competitive price" and, therefore, "a threshold multiplier of 140% would allow the Company to efficiently implement its RE Plan." 2 Tr 61-62.

The Attorney General objected to Consumers' proposal, asserting that "[t]he Company proposes to shift development risks from developers onto ratepayers. Specifically, the Company's proposal has the possibility of adding an additional $373 million to the already significant cost of the proposed RE Plan. Ratepayers will also receive no benefits for shouldering these additional development risks." 2 Tr 447.

The Attorney General noted that the U.S. Energy Information Administration (EIA) prepares a LCOE analysis in support of its Annual Energy Outlook (AEO). She stated that the most recent LCOE analysis was conducted in April 2023, and it:

> concerned new generation units entering service in the year 2028 with an estimated 30-year cost recovery period. EIA estimates a LCOE for region 5 (covering the majority of the lower peninsula of Michigan) of $27.41 per MWh in 2022 dollars for new onshore wind generation under the 2023 AEO reference scenario. Likewise, EIA estimates a LCOE for region 5 solar photovoltaic [(PV)] generation of $26.87 per MWh in 2022 dollars under the 2023 reference scenario. Even when examining EIA estimates assuming the removal of tax credits under the Inflation Reduction Act, the LCOE for these technologies is significantly less than that estimated by the Company.

2 Tr 458-459 (footnotes omitted). She also recommended that the Commission remind Consumers that in the settlement agreement approved by the June 23 order, the company agreed that only 50% of renewable energy resources acquired through competitive solicitations will be company-owned.

In response to Consumers' claim that the 140% multiplier is necessary to accommodate the risks associated with developers, MEC/NRDC asserted that the company failed to quantify the risks or provide evidence as to how the risks impact prices. MEC/NRDC also noted that according to Consumers, "[a] review of the solar bids offered that would achieve the Company's solicitation targeted capacity (500 MW per year), reveals that the marginal bid is approximately $97/MWh (or approximately 140%)," but that Consumers "never introduced that analysis into evidence and it does not appear in [their] workpapers. Nor has Consumers provided any rate impact or other analysis to demonstrate that acceptance [of] its proposal will not increase rates or charges." 2 Tr 406-407 (quoting 2 Tr 61). MEC/NRDC recommended that the Commission deny the company's request for *ex parte* approval of projects that are priced up to 140% of Consumers' LCOE. MEC/NRDC asserted that Consumers could still seek "approval of projects that are priced higher than 100% of the Company's projected LCOEs" in a contested case, such as an REP amendment, REP reconciliation, or a standalone proceeding. 2 Tr 407.

GLREA disagreed with Consumers' claim that there is a risk that developers may not pass along tax credits; rather, GLREA asserted that there is no risk if the bidding is actually competitive. Specifically, GLREA stated that "[i]f one developer didn't consider the tax credits in their pricing, but other bidders did include the effect of the tax credit in their pricing, the developer that didn't consider tax credits or planned on pocketing them would not win a contract." 4 Tr 560. In addition, GLREA argued that the risks associated with repealed tax credits, the MISO interconnection queue delay, tariffs on solar panels, inflated labor costs, and increased land prices are not new risks. GLREA stated that these risks "could be mitigated with terms and conditions in the contract . . . ." 4 Tr 562. Furthermore, GLREA asserted that Consumers failed to provide "evidence that developers are pricing in any particular risk; these suggestions regarding what developers may be considering or may consider in the future when setting their bid prices are purely speculative . . . ." 4 Tr 562.

GLREA also noted that in response to Consumers' December 8, 2022 IRP solicitation requesting 500 MW of solar, the company received 38 proposals that represented approximately 1,665 MW of capacity. In addition, GLREA stated that in response to Consumers' September 24, 2021 IRP solicitation requesting 500 MW of capacity, the company received 28 proposals representing 1,500 MW of capacity. GLREA contended that Consumers is receiving adequate bids, but that the issue is price. Although Consumers claims that the marginal bid is $97/MWh (or approximately 140%), GLREA asserted that "the Company's filing doesn't define what it means by 'the marginal bid' and provides no data on the bids received to support its assertion." 4 Tr 564.

GLREA noted that if the Commission does not approve the 140% multiplier and the company has insufficient bids below the modeled price, Consumers will need to seek cost recovery in a contested case, which will take longer than *ex parte* approval. However, GLREA asserted that this "is not an entirely bad outcome; developers will want the more expedited process, and may keep their bids lower to avoid a contested case. It would also allow intervenors other than staff to review the bids and issue discovery requests to ensure that the bidding process was truly competitive." 4 Tr 564; *see also*, 4 Tr 620.

In the event the Commission approves the 140% multiplier, GLREA argued that developers may bid high, knowing they can receive expedited approval without the review of intervenors in an attempt to acquire higher profits. GLREA stated that:

> [t]his is a low risk if a large number of unrelated bidders are bidding enough capacity, but the risk goes up the fewer bidders there are. The impact could be quite substantial. The Company projected the build cost at $27.8 billion, but if the average bid was just 20% higher than the Company's modeled price, it would increase the cost by (20% x 27.8 billion) = $5.56 billion.

4 Tr 564. Therefore, GLREA recommended that the Commission reject Consumers' proposed multiplier and, instead, approve 110.4% for solar and no multiplier for wind, which is based on data provided by LevelTen, a company that tracks renewable energy pricing.

GLREA contended that, to date, the Commission has not granted permission for *ex parte* approval for contracts that are substantially more expensive than the company's target price.

However, GLREA asserted that if the Commission grants Consumers' request for *ex parte* approval "for projects with a LCOE above the modeled cost by any amount, the Commission should limit the duration of that approval until the Commission's order in the Company's next REP case, where it can be reconsidered." 4 Tr 566.

MEIU stated that it supports the elements of Consumers' proposal that "could alleviate the administrative burden on the Commission, its Staff, the Company, and any third-party bidder under a potential PPA to facilitate timely approval of procurements." 4 Tr 655. However, MEIU contended that the company's proposal is incomplete "because it lacks sufficient elements and safeguards that would ensure a competitive and fair process." 4 Tr 655. If the Commission approves an *ex parte* approval process, MEIU recommended the following conditions:

- The use of a competitive bidding process overseen by an IA;
- A mandated 50/50 ownership split between the Company and third parties;
- A mid-size (1–5 MW) procurement carveout to comprise up to 10% of total new solar resources; and
- A process to periodically revisit the Company's LCOE targets for wind and solar energy resources.

4 Tr 656. MEIU asserted that if the Commission allows Consumers to acquire new renewable resources on an *ex parte* basis and without an IA, the Commission should direct the company to ensure, as reasonably as possible, that it maintains a 50/50 ownership split for new renewable resource procurements. MEIU argued that "[w]ithout such a requirement, given the Company's stated preference to own all new renewable resources, it is possible that any such unrestricted *ex parte* contract approval process may result in the procurement of more expensive, solely Company-owned resources." 4 Tr 656-657.

MEIU also asserted that an effective competitive procurement process must include an IA. According to MEIU, an "IA is important because it (1) oversees the procurement process, (2) conducts the evaluation and scoring of proposals, and (3) communicates its results to the utility in an anonymous manner for a utility to choose the comprehensively best partner for resource procurement." 4 Tr 657. MEIU contended that the Commission should require the use of an IA for any renewable resources procured through an amended REP and any renewable resources procured beyond the amended REP.

Additionally, MEIU stated that "any Commission authorization for *ex parte* project review be conditioned upon a commitment to revisit the Company's proposed LCOE targets for wind and solar resources by the time of filing of the Company's next RE Plan." 4 Tr 660. MEIU explained that to ensure the development of cost-effective solicitations that are beneficial to the company and its ratepayers, the Commission should determine an accurate and economically viable LCOE for Consumers' next amended REP. Moreover, MEIU asserted that:

> the landscape for renewable energy development is dynamic and fast-changing. In order for the Company to best incorporate up-to-date market information into its wind and solar LCOEs targets, [MEIU] recommend[ed] that the Company be required to update the LCOE targets every two years, or at the filing of each subsequent RE Plan, to reflect the most recent market sentiments.

4 Tr 661-662.

In response to the Attorney General's claim that the company's proposal shifts development risks from developers to ratepayers, Consumers asserted that the "proposal is not intended to avoid the rigid due diligence that is performed as part of each and every solicitation and simply execute contracts at almost any cost. Rather it is intended to expedite the delivery of new renewable energy resources and the associated attainment of renewable energy credit compliance pursuant to Act 235." 2 Tr 100. Consumers contended that the intention is not "to execute every new contract at 140% of the threshold baseline LCOE;" instead, the purpose "is to provide flexibility in the regulatory approval process so as to not further exacerbate the already slow onboarding of new renewable energy resources." 2 Tr 101. The company stated that it is mindful of the affordability impact of the amended REP on customers and, accordingly, designed its amended REP in a manner that balances the potential impacts by not imposing a revenue recovery mechanism.

Consumers also disagreed with the Attorney General that the company's baseline LCOE estimates are already higher than expected. The company stated that:

> solicitations are run by an independent administrator and the Company has not received any proposals which are in the vicinity of the LCOEs discussed by [the Attorney General], and the results of its solicitations are consistent with its projected LCOEs. [The Attorney General]'s reference point is Energy Information Administration ("EIA") Region 5 which covers Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. And while some of the available capacity factors for these states are similar, the siting availability, underlying construction costs, and interconnection requirements may vary.

2 Tr 101.

Furthermore, Consumers disputed MEC/NRDC's and GLREA's claims that the company failed to support the 140% threshold. Consumers asserted that it provided discovery responses, workpapers, and exhibits demonstrating that for "solar energy resource additions, . . . removal of the tax credits results in a 37% increase in the LCOE," and for "wind energy resource additions, . . . removal of the tax credits results in a 48% increase in the LCOE." 2 Tr 98. In addition, the company stated that "Confidential Exhibit A-46 (KDJ-6) presents and ranks the results of the Company's 2023 IRP solicitation based upon the solicitation criteria. This exhibit highlights the projects which would need to be selected to achieve the 500 MW target of the solicitation. The marginal project required to achieve the 500 MW target of the solicitation came in at a threshold multiplier of 139%." 2 Tr 98. Consumers contended that if the Commission rejects the company's proposed threshold, Consumers would need to request approval of renewable energy projects in a contested case, which may result in the company's inability to timely implement the projects and comply with the RPS.

Consumers also argued that MEC/NRDC's recommendation that the Commission reject the company's 140% threshold conflicts with MEC/NRDC's other suggestions. Specifically, the company stated that MEC/NRDC "proposes to revise the transfer price calculation which would allow for an increase in the amount of cost transferred to the PSCR. This proposal appears to request an increase in the level of costs transferred to the PSCR, an issue that is being argued against in the proposed rejection of the 140% threshold." 2 Tr 99. Additionally, Consumers noted that MEC/NRDC requests that the company accelerate its buildout of wind resources. However, the company asserted that MEC/NRDC's recommendation that the Commission reject the 140% threshold would result in the opposite outcome: "it could decelerate the Company's buildout of wind energy renewable energy resources due to the need to conduct a contested case prior to being able to move forward with project construction." 2 Tr 99. Consumers also disagreed with MEC/NRDC's recommendations that the Commission disallow REC-only contracts and modify the incentive REC criteria pertaining to peak time. The company asserted that these recommendations would effectively prevent Consumers from complying with the RPS.

Next, Consumers disagreed with GLREA that the company's LCOE calculations for wind and solar resources are inaccurate. The company argued that its "LCOE models were well founded and reflect current reality, that tax credits are still available, and tariffs have not significantly impacted the cost of renewable energy equipment." 2 Tr 105. However, Consumers agreed with GLREA that the authorization for *ex parte* approval should only extend to the company's next amended REP case.

In response to MEIU's recommendation regarding an IA, the company noted that it "currently utilizes IAs as part of its competitive procurement processes and has no intention of altering this practice." 2 Tr 363. Additionally, Consumers responded to MEIU's request that the company regularly update the LCOE targets for wind and solar energy resources by stating that it plans to do this "in each of its subsequent Renewable Energy Plan amendments." 2 Tr 365. However, for the reasons set forth in the Company-Owned Wind Energy Resources section above, Consumers objected to a mandated 50/50 ownership split between the company and third parties.

The Staff found the intervenors' concerns regarding *ex parte* approval of up to 140% of the LCOE to be unpersuasive and, instead, supported the company's proposal. The Staff stated that:

> [t]he Commission has provided *ex parte* review and approval of both PPA and Company-owned renewable energy contracts since the first REPs were approved in 2009, subject to [Act] 295 of 2008. This provided expedited treatment of submitted contract approval request applications (~90 days as opposed to more than a year), which sent a signal to renewable developers within Michigan that there was little to no regulatory risk of projects being tied up in litigation for a year or more, costing time and ultimately money from these delays (such as interest on loans, lease payments, and litigation expenses).

4 Tr 811. If the Commission were to deny Consumers' request for *ex parte* approval and require contested cases instead, the Staff contended that developers may believe that project approval will be prolonged by litigation and developers are likely to include a risk premium in future bids—if they bid at all. The Staff also contended that requiring a contested case proceeding:

> would most likely increase the cost of Company-owned projects as well, through interest on regulatory balances, lease payments, and inflation, during litigation as companies front significant costs for projects well in advance of asking for Commission approval, but also may not procure necessary items (i.e., panels, racking, transformers, turbine blades, towers, etc.) that are all subject to inflation or other world events, such as regional conflict and/or tariffs until approval has been given.

4 Tr 812.

Regarding Consumers' proposed LCOE threshold multiplier of 140%, the Staff stated the purpose is for planning only and the Staff does not view the 140% "as the actual costs projected at this point or a contingency allowance in the event of cost overruns for approved projects." 4 Tr 812-813. The Staff asserted that it reviews and evaluates the actual costs submitted by the company in the contract review process. Specifically, the Staff contended that it "audits the RFP process, proposals submitted in response to the RFP, and Company scoring methodologies before making a recommendation on that contract to the Commission." 4 Tr 813. The Staff stated that although the LCOE threshold multiplier of 140% may seem rather high, "this differential could be quickly realized if current federal tax credits are revoked (approximately 30%) and/or tariffs on imported components are in place, which is not entirely unlikely given the current administrative climate." 4 Tr 813. However, the Staff asserted that if a PPA or company-owned project exceeded the 140% threshold multiplier, the cost increase would have to be approved in a new contested case before that PPA or company-owned project could be approved through a contract review request application. In any event, the Staff recommended that "for future plans, the upper cost limit in REPs be tied to the upper cost limits included in the Company's most recently approved IRP and vice versa." 4 Tr 813-814.

In its brief, GLREA noted that:

> [a]fter rebuttal testimony was filed in the instant case, the [U.S.] House [of Representatives] Ways and Means Committee revealed a bill that would quickly phase out the federal tax credits for solar and wind facilities. GLREA recommend[ed] that the Commission direct the Company to modify their solicitation process to address this risk, by asking bidders to supply a quote with two prices. The "standard price" on bids would assume the tax credits continue, at least long enough for that project to qualify for the tax credits. An additional "contingency price" should be included in future bids, which would take effect if, and only if, the applicable federal tax credits were repealed prior to the project qualifying for them.

GLREA's initial brief, pp. 6-7 (citing 3 Tr 590). GLREA asserted that if the Commission does not wish to include a federal tax credit repeal "contingency price," then the Commission approve the four process modifications recommended by MEIU, along with the *ex parte* cap at 140%.

According to the Attorney General, Consumers admitted that it did not model the financial impact of the 140% multiplier and the company "appears to have no calculations, analyses, or other reasonable basis to believe that passing this 140% in administrative expenses on to customers could qualify for *ex parte* relief." Attorney General's initial brief, p. 25. And, in response to the company's claim that the Attorney General's reliance on the LCOEs in the EIA's AEO is misplaced, the Attorney General asserted that "EIA's AEO is a public forecast that the Commission has recognized as appropriate in the past as estimates of future natural gas prices within Integrated Resource Planning ("IRP") modeling." *Id*., p. 27 (citing the November 21, 2017 order in Case No. U-18418, p. 35).

MEC/NRDC noted that Consumers recently submitted seven projects for approval that are all significantly under the 140% multiplier threshold and that correspond with the estimate from the IRP. In MEC/NRDC's opinion, "Consumers' evidence for positing an increase in costs resulting from recent RFP responses must be weighed against the much lower costs realized in recent approved projects – with the latter given greater weight than Consumers' relatively thin evidence . . . ." MEC/NRDC's initial brief, p. 48. In addition, regarding Consumers' claim that the marginal project required to achieve the 500 MW target of the solicitation is at a threshold multiplier of 139%, MEC/NRDC asserted that the project referenced by the company is 5 MW, interconnected to Consumers' distribution system, and an atypical project. MEC/NRDC argued that "[b]ecause [the company's claim] is based on an atypical project from a single set of RFP results, the marginal bid from the 2023 IRP solicitation should not be given any weight . . . ." *Id*., p. 49.

MEC/NRDC also disputed Consumers' claim that without the 140% threshold multiplier, the company will have to seek approval in a prolonged contested case and, therefore, may not be able to timely comply with the RPS. MEC/NRDC asserted that "while that is theoretically possible, it has not been Consumers' experience in reality. [Consumers' witness] Mr. Johnston testified on cross that the contested cases on solar contracts Consumers has submitted for approval in recent years have all settled – and in the only case that had an intervention, 'beyond the prehearing, the time wasn't extensive.'" *Id*., p. 50 (quoting 2 Tr 144).

The ALJ acknowledged the concerns expressed by the intervenors, however he found that Consumers supported its proposed 140% threshold multiplier and recommended Commission approval. He stated that "[a]s explained by Staff and Consumers, and generally noted by GLREA, the current energy landscape, particularly as to inflation and the availability of federal tax credits for wind and solar, is creating uncertainty and risk for developers" and, therefore, the company's proposed 140% threshold multiplier is necessary to mitigate those risks and allow Consumers to meet the RPS. PFD, pp. 51-52. The ALJ also found persuasive the Staff's assertions that the actual costs will be reviewed and evaluated by the Commission.

The ALJ disagreed with the Attorney General's and MEC/NRDC's claims that Consumers' proposed 140% threshold multiplier will increase costs for customers and, thus, *ex parte* approval is not appropriate. He found "that approving the 140% LCOE is not contrary to [MCL 460.6a(3)]." *Id*., p. 52. However, the ALJ found MEIU's recommendation persuasive "that ex parte approval be contingent upon the Company's use of an IA in its RFPs and that the wind and solar LCOE targets should be regularly updated, as the Company has agreed with both of these conditions." *Id*. Furthermore, he stated that if Consumers is actually soliciting third-party PPAs in its RFPs, then an explicit 50/50 ownership split is not necessary.

The Attorney General excepts, asserting that Consumers "failed to demonstrate how the 140% factor is a necessary cost adder or that passing on such costs as requested is reasonable and prudent." Attorney General's exceptions, p. 4. Accordingly, she requests that the Commission reject the ALJ's recommendation on this issue.

In exceptions, GLREA contends that the ALJ's recommendation that the Commission adopt the 140% LCOE threshold is not supported by evidence on the record. Specifically, GLREA asserts that "unsupported speculative fears that an extravagant threshold of LCOE plus 140% is necessary to limit project delays (by cutting off any rights to a potential contested case) is highly exaggerated and fallacious." GLREA's exceptions, p. 2. GLREA reiterates the arguments set forth in testimony and briefing, described above. *See*, *id*., pp. 3-6.

GLREA appreciates the ALJ's recommendation that any Commission approval of the company's request for *ex parte* approval of wind and solar contracts up to 140% LCOE be conditioned on the use of an IA and the company updating its LCOE targets every two years in an REP filing. However, GLREA argues "that those conditions should be adopted without approving an extravagant threshold of LCOE plus 140% as the demarcation between *ex parte* versus contested case project approvals." *Id*., p. 3. GLREA requests that the Commission reject Consumers' proposed 140% threshold and, in the alternative, adopt a LCOE plus 110% for solar, but no margin factor for wind projects.

In reply to the Attorney General's and GLREA's exceptions, Consumers asserts that "[t]hese exceptions fail to recognize that the Company developed the 140% LCOE threshold based on what would happen if the federal tax credits were eliminated." Consumers' replies to exceptions, p. 8. Additionally, the company reiterates the arguments set forth in testimony and briefing, responding to the Attorney General's and GLREA's concerns that the 140% LCOE threshold is expensive and risky for customers. *See*, *id*., pp. 8-10.

The Commission finds that the ALJ's recommendation should be adopted. As noted by the Staff, it is reasonable for Consumers to consider consequences to renewable resource development if the federal tax credits are revoked. Accordingly, Consumers provided workpapers showing that removal of the tax credits increases the LCOEs for solar and wind energy resource additions. *See*, 2 Tr 98; Exhibits A-44 and A-45. The company also presented an exhibit that included the results of Consumers' 2023 IRP solicitation and that "highlight[ed] the projects which would need to be selected to achieve the 500 MW target of the solicitation . . . ." 2 Tr 98. Consumers asserted that the "marginal project required to achieve the 500 MW target of the solicitation came in at a threshold multiplier of 139%." 2 Tr 98. The Staff acknowledged that the company's proposed 140% threshold seems high, however the Staff stated that it allows a reasonable price range for projects in an uncertain administrative climate and helps ensure that the company can meet the RPS in the event there are unexpected cost increases for renewable energy. The Commission agrees. However, the Commission finds that the Staff's recommendation that "for future plans, the upper cost limit in REPs be tied to the upper cost limits included in the Company's most recently approved IRP and vice versa" should be approved. 4 Tr 813-814. Additionally, the Commission agrees with GLREA and Consumers that the Commission's authorization of the 140% threshold should only extend to the date of the order issued in the company's next amended REP and should be reviewed in that case. *See*, 2 Tr 105-106; 4 Tr 566.

The Commission agrees with the Staff and Consumers that approval of the 140% LCOE threshold is for planning purposes only and does not reflect a contingency allowance or the actual costs projected at this point in time. As noted by the Staff, "[a]ctual costs are reviewed and scrutinized through contract review request applications filed by the Company with the Commission, in which Staff audits the RFP process, proposals submitted in response to the RFP, and Company scoring methodologies before making a recommendation on that contract to the Commission." 4 Tr 813. In addition, as noted by Consumers, approval of the 140% threshold LCOE should not result in a situation in which every new contract is executed at 140% of the threshold LCOE. Rather, the purpose of the proposal is to provide needed flexibility in an uncertain climate. The company is still required to perform due diligence to determine the economic prudence of a potential contract. Therefore, the Commission finds that the potential *ex parte* approval of projects for inclusion in Consumers' REP that are priced up to 140% of the company's projected LCOE does not increase costs for customers and may be approved pursuant to MCL 460.6a(3).

The Commission also agrees with the ALJ's recommendation that approval of the company's *ex parte* request should be conditioned on Consumers' use of an IA in its RFPs. The company noted that it already uses an IA as part of its competitive procurement process and intends to continue the practice. 2 Tr 363. Furthermore, the Commission agrees with the ALJ, Consumers, and MEIU that the company's wind and solar LCOE targets should be regularly updated in Consumers' subsequent REP amendments. Finally, the Commission agrees with the ALJ that it is not necessary to order an explicit 50/50 ownership split. The Commission finds Consumers' testimony persuasive that it "competitively bids contracts under the RE Plan" and selects the lowest cost renewable energy resources. *See*, 2 Tr 82-85, 233. As discussed in the sections above, the Commission expects Consumers to explore and select the most economical, feasible, and prudent resources to meet its requirements regardless of ownership.

d. Transmission Studies

GLREA stated that "Consumers Energy needs to work with MISO to determine if transmission lines will support the proposed generation assets and . . . to provide the results of that investigation to provide capacity and location on the existing transmission lines as well as any MISO upgrades." 4 Tr 614.

Consumers disagreed, asserting that:

> [t]ransmission connected generation is required to be submitted to and studied by MISO through the MISO Generator Interconnection Process ("GIP"). Through the GIP, MISO determines the Interconnection Facilities and Transmission Network Upgrades required to support the proposed generation asset at the requested level of interconnection service. The GIP culminates in an executed Generator Interconnection Agreement ("GIA") which outlines the requirements and obligations for the proposed generation asset to interconnect to the Transmission System including the upgrades necessary to facilitate the interconnection. The Company actively works with MISO through the MISO GIP.

2 Tr 230.

The ALJ "agree[d] with Consumers that the Company already works with MISO through the GIP to ensure that proposed generation can be supported or whether upgrades are needed." PFD, p. 53. Therefore, he recommended that the Commission reject GLREA's suggestion.

No exceptions were filed on this issue.

The Commission finds that the ALJ's recommendation is reasonable and prudent and should be adopted.

e. Renewable Resource Acceleration

GLREA contended that to mitigate the risks associated with the timely completion of sufficient generation resources to comply with the RPS, Consumers should "[f]ront load the build plan with more capacity earlier in the schedule. This will slightly increase the cost (due to the time-value of money), but will allow for some schedule slippage." 4 Tr 577. GLREA noted that Consumers' current REP build plan was included in the proposed course of action (PCA) in the settlement agreement approved by the June 23 order. GLREA stated that "[t]he PCA called for adding 500 MW of solar in every year from 2027 - 2040. A front-loaded build plan would acquire more capacity in earlier years and less in later years." 4 Tr 578 (citing Exhibit A-19 in Case No. U-21090). MEC/NRDC also asserted that the Commission should direct Consumers to accelerate the procurement of new renewables, specifically wind resources. *See*, MEC/NRDC's initial brief, pp. 8-10.

Consumers agreed that front-loading the schedule may help with REC compliance. However, the company asserted that one of its "recent solicitations has shown that it would be incredibly difficult to accomplish an acceleration without the 140% LCOE threshold. As previously mentioned, the Company is concerned about customer affordability and in no circumstances would it propose to go beyond the proposed 140% LCOE threshold." 2 Tr 107 (citing Confidential Exhibit A-46). In addition, Consumers contended that it is not limiting the capacity that it acquires from recent solicitations. The company stated that "[t]he only limitation is an ability to acquire sufficient projects which are economic." 2 Tr 108.

GLREA stated that it is "reassured by the Company's response, and note[d] that a project's schedule becomes less important by front-loading the plan with more capacity. [GLREA] recommend[ed] that the Commission's order in the instant case specifically signal the Commission's willingness to approve contracts for *more* than the Company's planned 500 MW per year, if they are cost-competitive." GLREA's initial brief, p. 11 (emphasis in original).

The ALJ found that "the Company indeed appears to be willing and able to exceed the 500 MW per year projection for resource acquisition, provided the projects are economical. As such, the PFD does not find it necessary for the Commission to order Consumers to adjust its current practice." PFD, p. 55.

No exceptions were filed on this issue.

The Commission finds that the ALJ's recommendation is reasonable and prudent and should be adopted. The Commission notes that the company's proposed 140% LCOE threshold was approved, as discussed in the section above. The Commission expects approval of the 140%

LCOE threshold to assist in the accelerated procurement of new renewables, as noted by Consumers.

3. Sales Forecast

Consumers presented its electric retail sales forecast for 2024-2045, which includes bundled sales to residential, commercial, industrial, streetlighting, and inter-departmental classes, and excludes wholesale, intersystem, and choice sales. The company forecasted 3,792,124 MWh in sales to Industrial Large Economic Development (LED) customers in 2028, which increases to 8,667,407 MWh in 2045. *See*, Exhibit A-6. Consumers stated that "[t]he rapid advancement of artificial intelligence ('AI') and the need for large data centers to support this technology has had an impact on the Company's delivery forecast as reflected in the delivery forecast . . . ." 2 Tr 46. In addition, Consumers asserted that its sales forecast was used to project REC targets for 2023 through 2045. *See*, Exhibit A-33.

Regarding the participation growth for Rate LED, the Attorney General:

> [r]ecommend[ed] the Commission remove the increased REC requirement associated with incremental growth in the Company's LED rate after the year 2028. Growth in AI and the associated energy needs to support new data centers is a topic that many electric utilities throughout the country are currently addressing. Doubtless some of this growth will also occur in the Company's service territory. However, it is premature at the current time to include these loads when the Company cannot clarify how much of its additional load growth is associated with publicly announced projects versus private inquiries that are subject to change or outright cancellation. Section 22(3) of Act [235] requires that electric utilities file amended RE Plans with the Commission every two years, so these load additions can be included in future filings as the projects enter the public record.

2 Tr 471. Regarding the company's near-term forecasted additional LED electric sales, the Attorney General noted that Consumers filed a supplemental discovery response demonstrating that the sales are only associated with customers who have signed contracts with the company.

Accordingly, the Attorney General supported the company's near-term forecasted LED electric sales.

The CEOs opined that "[t]he biggest risk is that load growth will outpace renewable generation growth. In the initial years of the REP[,] the Company is well-positioned to address this risk . . . ," however, "the uncertainty around such forecasts . . . means that it is critical to develop robust and early planning which addresses a range of scenarios." 4 Tr 700-701. In addition, the CEOs asserted that Consumers' projected overall annual growth rate average of 4% for 2024-2031 seems relatively high. The CEOs stated that the National Renewable Laboratory's "2023 Standard Scenarios report, which provides a nationwide outlook for the U.S. electric sector, includes three different demand growth scenarios, ranging from 0.9% annually in the 'Low Demand Growth' scenario up to 2.8% in the 'High Demand Growth' scenario." 4 Tr 701. Furthermore, the CEOs noted that:

> [m]ore specific to the Midwest, MISO's most recent load forecast, published in December 2024, notes that peak demand is forecast[ed] to grow by 1 to 2% per year. However, in a presentation made in the same month, MISO indicated that growth rates up to 3.3% may also be possible, noting that current projections represent a three-fold increase over previous projections; this growth is attributed to an estimated 19 to 30 GW [gigawatts] of new data center load by 2040. Indeed, industry expert Grid Strategies noted in a December 2024 report that MISO's projections have increased steadily from 2022 through 2024.

4 Tr 701 (footnotes omitted). To mitigate the risks associated with increased load growth and possible failure to meet the RPS, the CEOs recommended that the company "develop a range of forecast scenarios, utilizing both their own information (as the projections in the REP seem to do) while also considering industry-wide forecasts. By utilizing a range of scenarios, the Company can be prepared to pivot quickly as new data becomes available over time to confirm which scenario is most likely." 4 Tr 703. The CEOs also requested that the Commission direct Consumers to model curtailment of renewables, including off-peak renewables production, on the

final PCA and any additional sensitivities that represent full decarbonization and/or high renewable penetration in the company's next IRP.

The CEOs also noted that the Attorney General may be correct to question the company's proposed load growth for Rate LED beyond 2028. The CEOs stated that "[i]f Consumers only plans for this future load growth based on the two year cycle of the REP process, there is significant risk that as load materializes the Company will not be able to meet its RPS obligations." 4 Tr 713.

In response to the Attorney General's claim that it is premature to include the load associated with data centers in Rate LED, Consumers stated that it "prepared its delivery forecast based upon the best information that it had available at the time of filing this amended RE Plan. To arbitrarily reduce the delivery forecast and assume that it can simply be added in the next amended RE Plan is negligent." 2 Tr 93. The company asserted that pursuant to Act 235, Consumers must comply with a significant increase in REC targets for 2030; if the company does not plan accordingly, it will likely be unable to comply. In addition, Consumers is not concerned that there will be an overbuild of renewable energy resources; rather, the company is more concerned about complying with the RPS in light of the potential risks with renewable energy resource asset growth. Consumers contended that "[m]uch of the Company's amended RE Plan is premised on its IRP glidepath for the addition of 8,000 MW of solar energy resources. The proposed glidepath for the addition of wind energy resources provides a significant amount of flexibility should the projected deliveries not materialize." 2 Tr 93-94.

Regarding the CEOs' claim that the company should develop a range of forecast scenarios, Consumers did not disagree but stated that an REP is not the proper venue to evaluate and establish IRP modeling requirements. The company contended that "[t]hose proposals can be addressed in various activities pursuant to Case No. U-21570 and/or through the Company's planned IRP stakeholder outreach." 2 Tr 97. Consumers agreed with the CEOs that it should model curtailment in the company's next IRP. *See*, Consumers' initial brief, p. 48.

The Staff "agree[d] that curtailment is an issue that should be modeled and considered by the Company, but [the Staff] believe[s] that the IRP is the appropriate venue to conduct this planning." 4 Tr 817.

In briefing, the Attorney General withdrew her recommendation to remove longer-term REC projections and, instead, suggested that the Commission adopt the CEOs' recommendation to develop a range of load growth scenarios that address the anticipated load demand from data centers. She stated that "[a]s recommended by [the CEOs], these scenarios should include both Consumers' own data and a survey of publicly available data, MISO reporting, announced data center projects, and other reporting from relevant authorities." Attorney General's initial brief, p. 43. The Attorney General requested that the Commission require Consumers "to file a more robust analysis as part of its 2026 IRP plan application." *Id*., p. 44. Furthermore, she supported the CEOs' recommendation that the company be directed to provide additional modeling for curtailment of renewables and storage planning in Consumers' next IRP.

The CEOs objected to Consumers' claim that an REP is not the proper venue to establish IRP requirements. In the CEOs' opinion:

> [t]he Company provides no legal support for this position. The Company cites no caselaw or statute that limits the Commission's authority. There is no reason that the Planning Parameters docket must be the exclusive means to order analyses to take place in the IRP. Relatedly, if the Commission chooses to do so, it may implement the CEO's recommendations within the planning parameters docket for all Michigan utilities.

CEOs' reply brief, p. 2.

The ALJ agreed with the CEOs that "the Commission has the authority to direct the Company to model various load forecasts as part of this REP proceeding. However, contrary to the CEO's claim, Consumers never asserted that the Commission did not have such authority, only that it would be more reasonable to address modeling requirements in another forum, namely the Company's next IRP." PFD, p. 59. The ALJ also noted that the company generally agrees with the CEOs that there is a need for various load growth scenarios. He found that Consumers' "sales forecast presented here is reasonable; it complies with the requirements of Act 295, and the forecast can be adjusted over time in IRP and biennial REP filings." *Id*. Furthermore, the ALJ recommended that the requirements for load growth scenarios should be established in the IRP Filing Requirements in Case No. U-21570 so that requirements are applicable to all regulated utilities.

The Attorney General excepts to the ALJ's recommendation that the requirements for load growth scenarios should be deferred to Consumers' next IRP case, stating that her concerns have heightened during the pendency of this case. She explains that, in this case, Consumers omitted large data customers from the REP forecasts and, "recently on July 31, 2025, the Company announced that it had 'reached an agreement with a new data center, which is expected to add up to 1 gigawatt of load growth in [its] service territory.'" Attorney General's exceptions, p. 8 (quoting Exhibit MEC-46, p. 1, in Case No. U-21859). In light of this development, the Attorney General requests that the Commission direct Consumers to proactively model growth scenarios for the increased demand attributable to this type of customer in the company's next IRP.

The Attorney General also notes that it is unclear whether the ALJ specifically addressed the Attorney General's and the CEOs' recommendations that Consumers conduct curtailment modeling in its next IRP that is separate from the large load demand scenario modeling. She states that "[t]o the extent the PFD intends a parallel finding on curtailment modelling as it finds for large load demand modelling, the Attorney General asks that the Commission reverse the PFD on that point as well." Attorney General's exceptions, p. 9.

In exceptions, the CEOs request that the Commission reject the ALJ's recommendation and direct Consumers to model various load forecasts as part of this REP proceeding. According to the CEOs, the ALJ "argu[ed] that the REP should not create IRP obligations for the Company. This approach elevates form over substance. The Commission should see past this argument and implement the best possible IRP modeling requirements, no matter the forum from which they spring. The CEO's recommendations derived from the development of a record in this case." CEOs' exceptions, p. 2.

The CEOs assert that they are not requesting that Consumers rework its REP to include the additional modeling scenarios. Rather, the CEOs recommend that the company run the various load growth scenarios in Consumers' next relevant proceeding—the company's IRP. The CEOs state that, "[a]lternatively, given that the Commission has yet to release the final IRP planning parameters and modeling requirements in U-21570, it could adopt these recommendations there for all Michigan utilities." *Id.*

The CEOs also contend that the ALJ did not address the CEOs' recommendations regarding the risk of curtailment or energy storage. The CEOs state that:

> [a]gain, the dispute around the adoption of these modeling requirements tracks the discussion above. While the Company agrees these would be sensible steps to take in an IRP, the Company protests that the REP is not the right venue to adopt IRP modeling requirements. As stated above, the CEO do not believe that should stand in the way of the best and most accurate possible modeling outcomes in the IRP.

Id., p. 3.

In reply, Consumers reiterates that it agrees that it should evaluate various load growth scenarios in an IRP, including storage and curtailment. However, the company restates that "particular IRP modeling requirements should not be established as part of this Amended RE Plan proceeding." Consumers' replies to exceptions, p. 11. Rather, Consumers asserts that IRP modeling requirements should be addressed in a separate proceeding opened for that purpose.

Consumers objects to the Attorney General's request that the company perform a curtailment analysis similar to the analysis included in the settlement agreement approved by the May 15 order. The company asserts that it "was not a party to the settlement agreement in Case No. U-21662 . . . and DTE Electric's agreement to perform any particular analysis in its next IRP as part of the resolution of Case No. U-21662 has no bearing on this case and is not binding on Consumers Energy." *Id.*

Finally, Consumers notes that the Attorney General's exceptions rely on a discovery response that was admitted as an exhibit in another case to demonstrate that the company's sales forecast fails to account for new load growth. The company asserts that "[i]t would be improper for the Commission to rely on testimony and exhibits from a different case, that are not part of the record here, to support its decision in this Amended RE Plan." *Id.*, p. 13. Accordingly, Consumers requests that the Commission reject the Attorney General's exception on this issue.

The Commission agrees with the ALJ that, in this case, Consumers' sales forecast was projected with the best available information at the time and finds that the sales forecast is reasonable and complies with the requirements of Act 295. However, the Commission finds that in the company's next IRP, Consumers should evaluate various load growth scenarios, including storage and curtailment, which will assist the company in responding to uncertainty in the forecasts. The Commission will consider including similar requirements for other rate-regulated utilities in the Michigan Integrated Resource Planning Parameters in Case No. U-21570.

4. Transfer Price

Consumers explained that, pursuant to the requirements of Act 295, "transfer price schedules should be representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the non-renewable market price component) through a long-term power purchase agreement for traditional fossil fuel electric generation." 2 Tr 338 (quoting the April 18, 2024 MPSC Staff Transfer Price Schedule, Case No. U-15800, filing #U-15800-0054, p. 2[2]). Consumers asserted that the transfer cost "is the total cost that the Company will transfer to power supply costs in accordance with MCL 460.1047(2)(b)(iv) associated with renewable generation obtained in accordance with MCL 460.1047." 2 Tr 332. The company also asserted that MCL 460.1047(2)(b)(iv) states that the renewable energy costs that are included in the PSCR plan shall be considered "a booked cost of purchased and net interchanged power transactions under section 6j of 1939 Public Act 3, MCL 460.6j." 2 Tr 332 (quoting MCL 460.1047(2)(b)(iv)). Consumers noted that the transfer price was first defined in the Temporary Order. The company proposed to continue the current transfer price and deferred accounting methods for company-owned assets through December 2045.

The company provided an explanation of the renewable energy resources that are recoverable through the transfer price in the company's amended REP:

> [t]his plan includes a total of 8,104 MW of solar projects which would be recoverable via the transfer price mechanism. Of that, 504 MW are solar projects already in the RE plan and 690 MW are due to the moving of 4 IRP assets into the RE plan. The remaining 6,910 MW are unnamed proxy solar projects, which

[2] The Staff's April 18, 2024 Transfer Price Schedule in Case No. U-15800 is unpaginated. Therefore, all citations reference the pages in natural order beginning with the first page of the report.

> includes 1,060 MW of unnamed proxy solar VGP projects. The additional 1,060 MW of proxy solar VGP projects combined with the existing 398 MW of named solar VGP projects and the 120 MW of named VGP wind projects brings the total VGP size to 1,578 MW.
>
> Additionally, this plan includes a total of 2,800 MW of unnamed proxy wind projects and 1,200 MW existing wind projects recoverable via the transfer price mechanism. Finally, this plan includes 20 MW of existing resources that are not wind or solar technologies which are recoverable via the transfer price mechanism.

2 Tr 328-329. The company also provided a detailed description of its proposed renewable energy generation through 2045 that is included in the transfer price. *See*, 2 Tr 332-335. Accordingly, Consumers stated that its projected transfer price for 2024-2045 is $72.67/MWh. 2 Tr 337.

The company asserted that it is important that the Commission preserve the current transfer price because:

> [w]hile the Company's modeling assumes that no costs from the Renewable Energy Program renewable energy resources will be transferred to the PSCR via the transfer price mechanism, the modeling does indicate that the original transfer price mechanism that was re-established in Case No. U-20483 needs to continue to remain in place to maintain a regulatory liability balance. Through the renewable energy cost reconciliation filings, the Company has previously committed to returning to limiting transfer price to the levelized cost of energy ("LCOE") for Company-owned facilities when the risk of dipping into a regulatory asset position is low. As a result of Michigan's Act 235, the Company is proposing to return to limiting transfer price to the LCOE for Company-owned facilities starting in 2034 and continuing for the remainder of the plan period. The modeling in this proceeding is based upon a return to that transfer price methodology beginning in 2034. The Company will continue to report on the status of the regulatory account balance in its annual renewable energy cost reconciliation proceedings.

2 Tr 337.

Consumers also requested that a simplified transfer price schedule replace the schedules approved by the Commission in Case Nos. U-15805 and U-16581 for the following assets: Beebe Renewable Energy, Fremont Community Digester, Harvest II Windfarm, Heritage Garden Windfarm I (wind energy), Heritage Garden Windfarm I (solar energy), Heritage Garden Stoney Corners Windfarm I (Phase 2), Heritage Garden Stoney Corners Windfarm I (Phase 3), Michigan

Wind 2, North American Natural Resources (Lennon), WM Renewable Energy (Northern Oaks), WM Renewable Energy (Pine Tree Acres), and EARP Solar Aggregate No. 5. In addition, the company proposed to assign Lake Winds Energy Park and Lake Winds Energy Park Repowered to their own unique transfer price schedule. According to the company, the new simplified transfer price schedules will:

> reduce the administrative burden, and reduce potential errors, associated with the existing Transfer Price schedules approved in Case Nos. U-15805 and U-16581. The existing schedules include a monthly on-peak rate, monthly off-peak rate, and monthly capacity rate. More recently, Staff proposed Transfer Price schedules do not include a capacity rate and include only a yearly total $/MWh rate. The Company is proposing to align the new Transfer Price schedule structure with that of Staff's schedules.

2 Tr 339.

Consumers explained that the two new transfer price schedules were developed using the following methodology:

> [t]he Company first modeled the total Transfer Cost of the units which would be assigned the new schedule and recorded the total forecasted Transfer Cost associated with those units using the existing Transfer Price schedules. The Company then modeled those same units using a proxy Transfer Price schedule which was structurally different from the existing schedule (structurally similar to Staff's proposed schedules – one rate for all energy delivered in a year, no capacity rate). The new (proxy) schedule was determined by, for each year, setting the Transfer Rate ($/MWh) for a given year such that the new forecasted total Transfer Cost associated with these units would be equal to (or nearly equal to) the total forecasted Transfer Cost associated with these units under the existing schedules. The value of the new single value (as opposed to on-peak/off-peak and capacity) for Transfer Rate ($/MWh) for a given year generally falls in between the former on-peak schedule rate and off-peak schedule rate but is not simply the average due to the pooled resource generation profile not producing during exactly 50% on-peak and 50% off-peak hours and the existing schedules inclusion of capacity-based transfer costs. To state simply, the newly proposed Transfer Price schedules are based on the existing Transfer Price schedules applicable to these units and is similar to a weighted average of the on-peak/off-peak and capacity transfer rates based on the resource pool's generation profile/capacity accreditation. The new Transfer Price schedules were created using the Transfer Price Forecast model such that there would be very little impact to the total Transfer Cost associated with these 14 units as seen in column (h) of Exhibit A-31 (ZSC-8).

2 Tr 339-340. Consumers contended that the purpose of the new transfer price schedules is to reduce the impact of the total cost transferred to the PSCR. According to the company, "for the period 2025 through the end of 2045, the newly proposed schedules result in an estimated net total decrease of $20 when comparing the forecasted total cost transferred to PSCR with the existing Transfer Price schedules," which is insignificant. 2 Tr 340-341.

However, Consumers stated that there are several factors that could affect how the new transfer price schedule performs compared to the existing transfer price schedule, including the on-peak/off-peak generation split. The company asserted that the new transfer price schedules were developed using the three-year historical average of generation during on-peak and off-peak hours. Consumers noted that "[a] divergence of the total transfer cost could occur if a unit significantly strays from its historical on-peak/off-peak energy production (including outages). Similarly, a significant change to the capacity credit (ZRCs) for these units in comparison to their three-year historic average could also create a divergence of the total transfer costs." 2 Tr 341. The company contended that these plants must be assigned to the new transfer price schedules, rather than the Staff's transfer price schedule, because it is important to utilize schedules that were developed in a relatively similar timeframe to when these plants were constructed or included in the REP.

MEC/NRDC objected to Consumers' proposed transfer price schedules, asserting that this issue should be addressed in the company's REP reconciliation case. In any event, MEC/NRDC asserted that the Staff's transfer price method is not the appropriate method for projecting transfer prices. MEC/NRDC noted that:

> in Section 51 of 2023 PA 235[,] the State of Michigan adopted Clean Energy Standards requiring that in 2035 through 2039 an electricity provider must provide 80% of its sales from a clean energy resource and that in 2040 and thereafter an electricity provider must provide 100% of its sales from a clean energy resource. A combined cycle gas plant can be considered a clean energy resource but only if it

> "uses carbon capture and storage [(CCS)] that is at least 90% effective in capturing and permanently storing carbon dioxide. If the department of environment, Great Lakes, and energy determines through a facility-specific major source permitting analysis consistent with applicable United States Environmental Protection Agency [(EPA)] rules, that a capture rate higher than 90% meets the best available control technology standard, as applicable that higher percentage shall be used instead of 90% for facilities permitted after the effective date of the amendatory act that added section 51."

2 Tr 402-403 (quoting MCL 460.1003(*i*)(ii)). In addition, MEC/NRDC contended that the EPA's "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 40 CFR 60, requires that new combined-cycle gas plants with annual capacity factors greater than 40% must operate with 90% effective carbon capture, which is to be installed and effective by January 1, 2032. MEC/NRDC opined that, because of the EPA rule, "it would not be prudent for a Michigan utility to construct a new combined cycle gas plant without carbon capture and storage. Since the transfer price is based on the levelized cost of a new combined cycle gas plant, the transfer price must account for the cost of carbon capture and storage." 2 Tr 403.

MEC/NRDC also recommended that the Commission approve an incremental addition to the transfer prices proposed by Consumers that is equal to the cost estimated by the EPA in 2019 dollars, adjusted for inflation. Specifically, MEC/NRDC stated that "[t]he transfer price method developed by Staff is based on a 400 MW capacity combined cycle plant. The [EPA] calculations most closely resembling the basis for the [Commission] Staff method is a 700 MW F-Class turbine, for which the [EPA] estimates a carbon capture and storage cost of $19/MWh in 2019 dollars," which should be increased by 19.3% to account for inflation for a total of $22.66/MWh. 2 Tr 404. Furthermore, MEC/NRDC recommended that the Staff develop a modified method for determining the transfer price that incorporates CCS. MEC/NRDC asserted that its proposed transfer price "will substantially reduce the incremental cost of compliance" and "lead to lower regulatory asset or higher regulatory liability balances." 2 Tr 405. MEC/NRDC requested that the Commission direct Consumers to include in its next REP amendment a modified transfer price that includes the costs of CCS.

GLREA contended that it is not reasonable to retain the transfer price methodology that was developed in 2008 in Case No. U-15800. In GLREA's opinion, the 2008 transfer price methodology may have encouraged renewable energy development at that time, but is no longer pertinent now that renewable energy generation is the lowest cost generation technology. GLREA asserted that "[t]he transfer price of a generation asset should only cover the actual cost of construction of the generation," while for PPAs, "the company should pay for the cost of energy negotiated plus the cost/value of the RECs or more simply competitively bid for renewable energy assets with RECs included." 4 Tr 617-618. In the alternative, GLREA stated that the company's REP and IRP could be used to develop plans and, in the short term, to propose ready-to-build projects wherein the Commission could supervise the bidding process and evaluate construction cost recovery in a rate case.

ABATE objected to Consumers' new transfer price schedules proposed to replace the schedules approved in Case Nos. U-15805 and U-16581. ABATE stated that its:

> understanding is that the Transfer Price is used to classify renewable resource costs between demand and energy when those costs are reflected in the PSCR in a base rate case. If the Company recalculates the Transfer Price schedules that were approved in Case Nos. U-15805 and U-16581 to eliminate the capacity component, it is unclear how the Company would maintain the appropriate classification of costs for the assets to which the new Transfer Price schedules would be applicable, when those costs are reflected in the PSCR in a base rate case.
>
> Given that the costs of renewable resources are largely fixed costs and those resources contribute toward meeting the Company's capacity needs, it would be

> entirely inappropriate to cease classifying a portion of these costs as demand-related when they are reflected in the PSCR in a base rate case. The demand-related portion of costs should, at a minimum, be equal to the capacity-related portion of the Transfer Price schedules approved in Case Nos. U-15805 and U-16581.

4 Tr 727. ABATE also expressed concern regarding how Consumers' new transfer price schedules perform compared to the existing transfer price schedules. Specifically, ABATE stated that the company's new transfer price schedule may have "a divergence from the three-year average on-peak/off-peak generation split, or changes to the capacity credit (Zonal Resource Credits) in comparison to their three-year historic average," and that it is unknown whether these variances could occur during the REP. 4 Tr 728 (citing 2 Tr 340).

Additionally, ABATE opposed MEC/NRDC's request that the Commission adopt a transfer price schedule that is based on a new combined-cycle gas plant with CCS. ABATE stated that:

> MEC-NRDC's proposal would add \$22.66/MWh to the existing transfer price. For reference, compared to the Company's forecasted transfer price of \$72.67/MWh for the RE Plan period, an adder of \$22.66/MWh would represent a 31% increase, although it's important to note that this could further increase over time as updated and localized CCS cost estimates are incorporated in future cases.

ABATE's initial brief, p. 3 (citing 2 Tr 360-362, 401-406; 4 Tr 736-741, 804-808).

ABATE noted that, after technical conferences were conducted in Case No. U-15800 and after much deliberation, the Staff found that the levelized cost of a new combined-cycle gas plant is analogous to the market price for a long-term PPA for traditional fossil fuel electric generation and, therefore, the most appropriate proxy for developing the transfer price schedule. ABATE asserted that, "[c]ontrary to this deliberative process and determination, and rather than comprehensively reevaluate the transfer price method based on the factors set forth in MCL 460.1047(2)(b)(iv), or whether an alternative proxy may be appropriate, the MEC-NRDC proposal here would simply add additional costs to this NGCC [natural gas combined-cycle] plant proxy price." ABATE's initial brief, p. 5. In ABATE's opinion, it is unreasonable and premature to adopt MEC/NRDC's proposal and, instead, ABATE recommended that the Commission direct the Staff to host a deliberative workgroup to resolve this issue.

Consumers also disagreed with MEC/NRDC's proposal, stating that it does not align with the Commission's current transfer price schedule methodology. Similar to ABATE, the company contended that this issue should be addressed by a workgroup and "not in a standalone case for a single utility." 2 Tr 362.

The Staff agreed with Consumers that the original transfer price mechanism that was re-established in Case No. U-20483 should remain in place but noted that transfer prices are adjusted and approved in annual reconciliations. The Staff also supported the company's proposal to modify the transfer price schedule that was approved in Case Nos. U-15805 and U-16581. In the Staff's opinion, "this modification, as proposed by Company witness Cole, is a much simpler and transparent transfer price schedule than the Company's existing transfer price schedule that is applied to Lake Winds Energy Park." 4 Tr 797.

In response to MEC/NRDC's recommendation that the transfer price methodology be based on a new combined-cycle gas plant with CCS, the Staff stated that it would not object to the current methodology being reviewed or reevaluated. However, the Staff disagreed with MEC/NRDC that the "Staff's current methodology is flawed in light of current events." 4 Tr 804. The Staff asserted that the use of a new combined-cycle gas plant as a proxy to determine the current transfer price schedule is not inconsistent with the requirements of Act 235, which directs electric providers to meet the clean energy standards of 80% beginning in 2035 and increasing to 100% in 2040. Specifically, the Staff explained that its:

> transfer price methodology is representative of what a Michigan electric provider would pay if it were to obtain energy and capacity from the market through long

> term power purchase agreements (PPA). It is assumed that the PPA prices would converge towards the market pricing set by an NGCC. Currently, the transfer price schedule is updated annually by Staff, filed in Case No. U-15800, and then utilized by several rate-regulated electric providers, including Consumers Energy Company (Consumers or the Company), to develop renewable cost reconciliation filings and renewable energy plans (REP). All but one of the Michigan rate-regulated utilities are Midcontinent Independent System Operator (MISO) market participants. MISO includes fifteen states and operates in the Canadian province of Manitoba, jurisdictions which are clearly not subject to Michigan clean energy laws and policies. While there is a locational component to the MISO market pricing through congestion for Locational Marginal Pricing and Local Clearing Requirement for capacity, the energy and capacity market is not clearly defined by state borders or state policies. It would be hard to absolutely define what impact Michigan's clean energy laws will have on future energy and capacity prices through all of MISO and if future PPAs will converge towards the price of a NGCC with carbon sequestration or remain close to that of a traditional NGCC.

4 Tr 804-805 (footnote omitted). The Staff also stated that new combined-cycle gas plants could be built in Michigan if the utility offsets the generation with an equal amount of clean energy system generation. However, the Staff acknowledged that due to the requirements set forth in Section 111(b) of the federal Clean Air Act, 40 CFR 60, and Act 235, the future of natural gas plants in Michigan is somewhat uncertain. Accordingly, the Staff asserted that "[d]ue to the uncertainty around the future of natural gas generation and what impact these changes may have on market pricing, it is premature to make changes to the transfer price proxy, as proposed by MEC-NRDC . . . ." 4 Tr 806.

Furthermore, the Staff argued that increasing the transfer price, as requested by MEC/NRDC, would not impact the method for cost recovery of renewable energy for PPAs but would affect company-owned facilities. The Staff explained that Section 47(2)(b)(iv) of Act 235, MCL 460.1047(2)(b)(iv), states that the company shall recover the cost of a PPA or the transfer price, whichever is lower, through the PSCR mechanism. The Staff asserted that:

> Company-owned facilities are not subject to this "lesser than" restriction. For a Company-owned facility, if required to recover a transfer price that adds costs associated with carbon capture as proposed by MEC-NRDC witness Jester, it would

> result in a significant increase in the amount of cost recovered through the PSCR, which would greatly reduce the balance associated with the incremental cost of compliance (regulatory asset/liability). Since the Company is not currently requesting a surcharge for the incremental cost of compliance, there is no need to contemplate an increase in the costs recovered through the PSCR at this time.

4 Tr 806. The Staff contended that other methodologies could be considered for establishing a transfer price proxy, such as solar generation, but maintained that the Staff's current methodology is still a valid option. The Staff asserted that if the Commission would like to reevaluate the current transfer price methodology, the Staff recommended that the Commission direct the "Staff to convene a workgroup, including all rate-regulated utilities and interested parties, with the objective to review and potentially reevaluate the existing Staff transfer price methodology to determine if/how it should be updated, as there are many potential options that could be appropriate outside of the existing methodology or that proposed by MEC-NRDC." 4 Tr 807-808.

Next, the Staff disagreed with ABATE's claim that if the current transfer price methodology is changed, the proportion of demand-related costs should be maintained. The Staff stated that its: "preference would be that the determination of the transfer price by capacity and energy portions in the same manner as was previously done be maintained. To the extent it is not, the proportional split of the transfer price between capacity and energy should be maintained rather than locking in the demand portion, as it better reflects prior practice." 4 Tr 880.

In addition, the Staff does not fully support GLREA's request that the transfer price be based on the cost of renewable generation built. The Staff stated that:

> the transfer price was intended to separate the additional cost of renewable over traditional generation and treat the cost that would be associated with the generation were it not renewable the same way as traditional generation costs. With regard to PPAs, to the extent that the transfer price is higher than the cost of renewables, customers do not pay more for the renewables than they cost through the transfer price. Instead, the amount of cost included in the PSCR through the transfer price is the actual cost if lower than the transfer price. For Company-owned generation, the Company is currently (and temporarily) allowed to include through the transfer

> price the higher of the transfer price or the levelized cost of the facility. However, this does not result in higher costs being borne by customers as any "overpayment" through the transfer price is recorded to the regulatory liability under the REP and accrues to the benefit of customers, rendering the impact on them neutral over time. For this reason, GLREA witness Rafson's proposals on this matter should be rejected for the purposes of the instant case. However, revisiting the use and purpose of the transfer price, as well as its calculation, given that renewables have effectively become what the Company is building anyway, may be appropriate.

4 Tr 881-882. The Staff also noted that in the settlement agreement approved by the May 15 order, the parties agreed to participate in a transfer price technical conference. The Staff contended that by the time the reconciliation is conducted in this case, the transfer price issue may have been evaluated by persons participating in the technical conference and decided by the Commission.

MEC/NRDC noted that, according to the Staff, because Consumers operates within the MISO market, which has jurisdictions that are outside of Michigan, it is not necessary to base the transfer price schedules on Michigan-specific clean energy laws and policies. MEC/NRDC disagreed, stating that Act 235 "does not say anything about using an average MISO-wide market price to calculate transfer prices. MISO is geographically enormous and prices vary drastically among its many different local resource zones – so it is unclear that such a concept would have any usefulness at all." MEC/NRDC's initial brief, pp. 63-64 (footnote omitted).

Next, MEC/NRDC noted that the Staff states that transfer price schedules should be representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the market price component) through a long-term PPA. However, MEC/NRDC asserted that on cross-examination in a DTE Electric case the Staff "acknowledged: 'It is probably unlikely that we would see any of our rate-regulated electric providers enter into a long-term contract for a natural gas combined cycle plant without . . . carbon capture and sequestration, although it is not impossible . . . that they could, it's just not likely.'" *Id*., p. 64 (quoting 2 Tr 69-

70 in Case No. U-21662). In addition, MEC/NRDC argued that the Staff failed to provide any other certain scenarios in which a combined-cycle gas plant without CCS would be built in Michigan. Therefore, MEC/NRDC asserted that it is unreasonable for the Commission to continue to base the transfer price on a proxy combined-cycle gas plant that does not have CCS.

Finally, like the Staff, MEC/NRDC noted that the settlement agreement approved by the May 15 order directed the Staff to host a symposium on transfer prices. MEC/NRDC asserted that the "workgroup has met, and Staff will be issuing a report later this summer. . . . The Commission should not approve Consumers' transfer price schedule in the meantime, because – as explained in MEC-NRDC's initial brief – there is no substantial evidence to support it and transfer prices are approved in the reconciliation case – not the plan." MEC/NRDC's reply brief, p. 10.

ABATE objected to MEC/NRDC's argument that, because the transfer price is based on the levelized cost of a new combined-cycle gas plant, the transfer price should now include the cost of CCS pursuant to state and federal rules. ABATE stated that, "[a]s this recommendation rests on the tenuous assumption that the transfer price should and will continue to be based on the levelized cost of a new combined cycle gas plant, the Commission should reject MEC-NRDC's recommendation." ABATE's reply brief, p. 4. In addition, ABATE agreed with the Staff that it is not reasonable to conclude that a combined-cycle gas plant with CCS is the most appropriate proxy given the manner in which the transfer price is calculated and the cost it is meant to reflect. ABATE stated that "there are a number of different resources which may serve as reasonable proxies for the transfer price, not to mention the myriad factors for determining the transfer price set out in MCL 460.1047(2)(b)(iv)" and "[e]xploring those options based on developments in renewable technology since the transfer price methodology was established over a decade ago is the purpose of the symposium established in Case No. U-21662." *Id.*, pp. 6-7. Therefore, ABATE recommended that the Commission reject MEC/NRDC's proposals and, instead, allow the workgroup to develop an updated transfer price methodology.

The ALJ agreed with MEC/NRDC and GLREA that the current transfer price methodology should be re-examined and possibly modified. In addition, he found MEC/NRDC's arguments persuasive that, pursuant to Act 235, a combined-cycle gas plant with CCS must replace a traditional combined-cycle gas plant as the proxy. However, the ALJ stated, "as noted by Staff, all potential proxies should be explored, such as the use of a solar facility, which MEC-NRDC found reasonable." PFD, p. 71. He agreed that the settlement agreement approved by the May 15 order directed the Staff to convene a transfer price methodology workgroup but "disagree[d] with MEC-NRDC that the Commission should reject Consumers' transfer price schedule in the meantime because MEC-NRDC contends there is no substantial evidence to support it and transfer prices are approved in the reconciliation case." PFD, p. 71.

The ALJ found Consumers' proposal for the new transfer price schedules to be reasonable, noting that the Staff's support of the proposal was persuasive. He agreed with the company that the impact on the total cost transferred to the PSCR through use of the new schedules is negligible. Additionally, the ALJ found that "there is sufficient evidence on the record in this case to approve the Company's request until the appropriate proxy for the transfer price can be determined via the symposium." *Id*., pp. 71-72. He however declined to recommend approval of MEC/NRDC's suggested changes to the transfer price methodology, asserting that these issues will be addressed in the workgroup. Finally, the ALJ disagreed with ABATE "that if the current method of determining the split between energy and demand portions of the transfer price is changed, that the proportion of demand-related costs be maintained," and instead agreed with the "Staff that maintaining the current proportional split would be more appropriate." *Id*., p. 72.

In conclusion, the ALJ recommended that:

> the Commission continue the current transfer price methodology and regulatory liability balance for Company-owned assets in the REP through December 2045 and approve Consumers' simplified transfer price schedules to replace those approved Case No. U-15805 and Case No. U-16581. This PFD also recommend[ed] that the Commission direct that the symposium ordered in Case No. U-21662 be continued to ensure it addresses and determines the appropriate proxy for the transfer price going forward and whether any modifications to the transfer price causes changes to the regulatory asset/liability that necessitates changes to the disbursement schedule of the projected final regulatory liability.

Id., pp. 72-73 (citing ABATE's reply brief, p. 11).

In exceptions, MEC/NRDC asserts that the Staff did not unequivocally support Consumers' continued use of a proxy combined-cycle gas plant without CCS and, therefore, the Commission should not rely on the Staff's support for the company's position on this issue. MEC/NRDC also states that "the modest impact of the proposed transfer price schedule on the total cost transferred to the PSCR in the short term is not a valid basis to approve the schedule if there is not substantial evidence to support it." MEC/NRDC's exceptions, p. 16. Rather, MEC/NRDC argues that the company failed to provide any evidence that a combined-cycle gas plant without CCS is a reasonable proxy for setting the transfer price.

In addition, MEC/NRDC notes that the transfer price symposium has already been conducted. According to MEC/NRDC, "[t]he draft Staff report does not make any recommendations one way or another – it simply summarizes the presentations and comments that have been submitted. There is an opportunity for comments on the Staff report, but because the Staff report is mainly a summary of presentations and comments it is unclear what the path to a decision on this issue will be." *Id*., p. 17. Thus, MEC/NRDC request that the Commission reject Consumers' proposed transfer prices and, instead, find that transfer prices must be based on a proxy combined-cycle gas plant with CCS. Alternatively, MEC/NRDC recommend revising the transfer prices to equal the actual cost of Consumers' solar resources. In any event, MEC/NRDC does not support deferring these issues to a symposium that will not result in a decision.

In reply, ABATE contends that it is "premature at this time" to direct Consumers to include the costs of CCS in the transfer price schedule. ABATE's replies to exceptions, p. 7. ABATE asserts that "[c]onsidering the significant technological and cost developments in renewable energy resources since the transfer price was originally established, a more comprehensive approach to establishing a transfer price cost is needed than simply directing one specific utility to file a transfer price reflecting one specific resource in its REP reconciliation proceeding." *Id.*, p. 8.

ABATE also objects to MEC/NRDC's claim that the transfer price should be based on a proxy combined-cycle gas plant with CCS because "any gas plant operating in Michigan past 2034 must be 90% effective in capturing and permanently storing carbon dioxide" to comply with the clean energy standard. ABATE's replies to exceptions, p. 7 (quoting MEC/NRDC's exceptions, p. 13). ABATE contends that MEC/NRDC's proposal to base the transfer price on a state standard for one specific resource that is not effective until 2034 is unreasonable. According to ABATE, "while the transfer price is meant to reflect the market cost of a long-term PPA, there is no evidence on the record that the most likely market cost of a long-term PPA is that of a natural gas resource with estimated CCS costs." ABATE's replies to exceptions, p. 9. ABATE argues that there are other options on which to base the proxy, which should be reviewed thoughtfully and visibly in a workgroup and that considers the factors in MCL 460.1047(2)(b)(iv) and the market costs of a long-term PPA.

Consumers replies to MEC/NRDC, asserting that "[r]evisiting the transfer price calculation is premature. This is especially true if the revisions were to only be applicable to Consumers Energy. Moreover, the Company maintains that if a new methodology is not adopted in this proceeding, then the Commission's current methodology should stay in place and be used for the Company's RE Plan." Consumers' replies to exceptions, p. 14. And, responding to MEC/NRDC's concern that the symposium has already occurred and no decisions resulted from the event, the company contends that the workgroup is ongoing and the Staff's final report is not yet due. Consumers asserts that any updates to the transfer price methodology should be discussed by the workgroup—not in this proceeding.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted. The current transfer price schedule was approved in the Temporary Order and, because of the significant passage of time, the enactment of new energy laws, and the changing energy landscape, it is fitting to revisit this issue. However, as noted by the ALJ, the most appropriate venue to explore and evaluate this issue is a workgroup that involves all rate-regulated utilities and interested persons. In the May 15 order, the Commission directed the Staff to host a symposium to explore and address the transfer price methodology and to issue a report. As above, the Commission finds the most appropriate path is for the Commission to provide additional guidance based on the issues raised in the symposium and summarized in the recently-filed report.

The Commission agrees with the ALJ that until the Commission adopts a new transfer price methodology, Consumers' proposed transfer price schedule should be approved in this case. As noted by the Staff, the current transfer price utilized by the company was adopted in Case No. U-20483 to address an issue with Consumers' regulatory liability/asset position. The Staff acknowledged that with the enactment of Act 235, Consumers is no longer required to carry a regulatory liability balance. However, the Staff contended that it is reasonable to continue the methodology, at least for the immediate case, "to balance the ICOC between a regulatory asset and regulatory liability position." 4 Tr 796. The Commission agrees.

The Commission also finds that the new transfer price schedules proposed by Consumers should be approved to replace the existing transfer price schedules approved in Case Nos. U-15805 and U-16581. The Commission finds persuasive the company's claim that the new transfer price schedules will reduce administrative burdens and potential errors and will better align with the transfer price schedules proposed by the Staff. In addition, Consumers asserted that the new transfer price schedules will have a negligible impact to the total cost transferred to power supply costs. *See*, 2 Tr 340-341. The Staff supported the company's proposal and contended that it is a "much simpler and transparent transfer price schedule than the Company's existing transfer price schedule . . . ." 4 Tr 797.

The Commission declines to approve ABATE's request that if the current method of determining the split between energy and capacity in the transfer price is changed, the portion of demand-related costs should be maintained. The Commission finds the Staff's argument on this issue persuasive. *See*, 4 Tr 880.

5. Incremental Cost of Compliance

Consumers provided the ICOC with the renewable energy standards for a 20-year period. *See*, Exhibit A-4. The company asserted that the ICOC calculation in this case is the same as the ICOC calculation in the REP amendment approved by the August 22 order; however, in this case, it includes an FCM for any new PPAs as set forth in MCL 460.1047(2)(a)(v)(C). More specifically, Consumers explained how the ICOC is calculated in Exhibit A-4, line 2:

> This line reflects all projected financing and capital costs (including a Return on Common Equity ("ROE") investment), depreciation expense, general taxes, and Operation and Maintenance ("O&M") expenses associated with the Company's investment to build renewable energy systems as part of its RE Plan to comply with 2008 PA 295 ("Act 295"), as amended by 2016 PA 342 ("Act 342") and Act 235 and the investments made to provide resources for customers electing to participate in a Voluntary Green Pricing Program ("VGP"), as authorized by Section 61 of Act 342.

2 Tr 176-177. In addition, the company asserted that the projected capital expenditures, PPA expense, and O&M expense in its amended REP are based on projects already approved by the Commission and in commercial operation. Regarding the items on line 9 in Exhibit A-4, Consumers stated that they are the estimated value of federal tax credits to encourage the development of renewable energy that the company expects to receive during the REP period.

GLREA contended that the existing federal tax credits will not continue through the entirety of the REP period. GLREA asserted that federal tax:

> incentives at most will continue through the IRA [federal Inflation Reduction Act] incentive period which tails off to zero starting in 2032. Thus, no more than 7 years of federal tax incentives should be considered.
>
> It is our opinion that the company's assumed tax credits in the REP of approximately $8.9 billion are both extremely high and fail to show the impact of the REP on customers. The calculations like the LCOE is low by the amount of the tax credits assumed. If these incentives are not received the result would likely greatly increase the cost recovery and result in much higher customer rates.

4 Tr 624-625.

Consumers noted that GLREA assumes that there will be zero tax credits for projects that will reach commercial operation after 2032. The company stated that "the IRA establishes a phase out for the credits, by 25% annually from 100% to 0% in the latter of 2032 or the year in which Treasury determines that annual greenhouse gas emissions from the production of electricity in the US are equal to or less than 25% of the annual greenhouse gas emissions for 2022." 2 Tr 197. However, Consumers contended that there is no published forecasted data that predicts this date and, in the past, the U.S. government has extended sunset provisions for renewable energy tax credits.

The ALJ "agree[d] with Consumers that, based on the information available when this case was filed, Consumers inclusion of federal tax incentives after 2032 was reasonable. If circumstances change, the Company may update its [ICOC] calculation in the future." PFD, p. 74.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

6. Revenue Recovery Mechanism

Consumers asserted that it is not proposing a revenue recovery mechanism to recover its ICOC in this case. The company explained that:

> [w]hile the Company's filing reflects that the Company will experience incremental costs of compliance on an annual basis through 2034, the incremental costs of compliance turned decidedly negative in 2035 through 2041, resulting in a projected regulatory liability at the end of the 20-year RE Plan period. As such, a levelized revenue recovery mechanism, as provided for in MCL 460.1045(3), for the 20-year period is unnecessary.

2 Tr 58. Consumers also contended that if it were to implement a revenue recovery mechanism for a shorter period, in effect, it would pre-pay for company-owned renewable energy resources that would benefit future electric customers and may require a large revenue recovery mechanism credit surcharge for future beneficiaries of company-owned renewable energy resources. Furthermore, Consumers stated that:

> [i]n addition to following principles of cost causation, the Company also recognizes that it may ultimately solicit and execute contracts for a higher percentage of renewable energy resources as compared to its proposed plan. That scenario would lead to far lower incremental costs of compliance and, ultimately, an even greater need to avoid the implementation of a revenue recovery mechanism.

2 Tr 58. In the event there is a large regulatory liability balance in 2037 and beyond, the company asserted that it will adjust the revenues to minimize the balance. For example, Consumers stated that potential options for reducing the balance "include a reduction to the transfer price and/or the

implementation of a credit surcharge. However, given the 20-year RE Plan period and the periodic filing of RE Plan Amendments, the Company has sufficient time to address that potential in future RE Plan Amendment filings." 2 Tr 59; *see also*, Consumers' initial brief, pp. 37-38.

MEC/NRDC contended that, according to Consumers, the company will have a regulatory liability balance of approximately $49.9 million at the end of 2024, a regulatory asset until 2034, and then will have a regulatory liability until 2045, with a final balance of $332.7 million. MEC/NRDC noted that the company plans to forgo a surcharge when it has a regulatory asset because the company expects to have a regulatory liability in the late 2030s. MEC/NRDC stated that, when Consumers has a regulatory liability, it will "limit transfers of costs to PSCR to levelized cost of renewable energy from 2034 in order to minimize the accrual of a regulatory liability." 2 Tr 408 (citing 2 Tr 187-188). MEC/NRDC supported the company's plan to forgo surcharges in anticipation of a regulatory liability. However, if the Commission accepts MEC/NRDC's recommendations regarding the transfer price, the accumulation of a large regulatory asset may be eliminated. In that case, MEC/NRDC suggested that "the Commission direct the Company to either eliminate the use of a regulatory liability or to early create an appropriate sur-credit to disburse the projected regulatory liability by 2045. This analysis should be done in Consumers Energy's next amendment of its REP." 2 Tr 409.

The ALJ "agree[d] with Consumers that regular REP filings will allow for sufficient scrutiny and adjustment of any regulatory asset or liability occurring over the plan period. As noted above, this PFD recommends that the changes proposed by MEC-NRDC to the transfer price be rejected for now. As such, [MEC/NRDC]'s concerns regarding the future regulatory liability are moot." PFD, p. 76.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

7. Voluntary Green Pricing Program

Consumers noted that in the August 22 order, the Commission removed the 1,000 MW limit on the addition of new wind and solar facilities to serve the Renewable Energy Program so long as the company achieves subscriptions totaling 75% of the expected energy production. Accordingly, Consumers proposed "to build, own, and operate nearly 1.1 GW of VGP solar facilities located in the state of Michigan." Consumers' initial brief, p. 41; *see also*, 2 Tr 180. The company also noted that the residential Renewable Energy Program and the Green Giving Program were commenced on January 1, 2025, and the company "has projected subscription rates for each of these new programs which support the addition of renewable energy resources which, all else being equal, support a lower cost RE Plan for non-subscribing customers." 2 Tr 67.

GLREA asserted that "the obligation of not building new energy resources until subscriptions total at least 75% of expected energy production will create an unreasonable burden on residential and small commercial customers . . . ." 4 Tr 615. By contrast, GLREA noted that for the industrial VGP program, any capacity that is not used for VGP will be used to comply with the RPS as a company-owned asset. GLREA opined that this approach is much more reasonable than Consumers' residential offering and should be provided to all customer classes.

However, GLREA objected to Consumers' industrial VGP program, stating that "[t]he program improperly provides for the building of renewable energy assets specifically for industrial customers. Presently, between the Economic development tariff and VGP, nearly ½ of industrial clients have effectively opted out of Consumers legacy generation pool leaving the commercial and residential customers to pay for these more expensive generation costs." 4 Tr 616.

Furthermore, GLREA argued that the company's commercial/residential VGP is not equivalent in value to the industrial VGP, explaining that the generation assets Consumers proposed for the commercial/residential VGP are twice as expensive as the industrial VGP LCOE.

In response to GLREA, Consumers stated that the 75% subscription requirement was approved in the December 9, 2021 order in Case No. U-20984 to ensure that the addition of VGP assets did not outpace subscriptions and to minimize the cost impact on PSCR customers. The company noted that the August 22 order continued the 75% subscription policy. Moreover, the company contended that:

> [a]ll customer types (residential, small business, commercial and industrial) participating in the Renewable Energy Program are served by a single resource pool of renewable energy facilities. Therefore, the 75% subscription level for new assets will be achieved through subscriptions from residential, small business, and commercial and industrial customers. As such [GLREA]'s concerns are unwarranted.

2 Tr 108. Additionally, Consumers asserted that the Renewable Energy Program is available to all customers, regardless of class, and no customer class has an advantage in price. The company disagreed with GLREA that non-subscribing customers subsidize VGP customers; rather, "VGP customers are required to pay for all costs associated with VGP programs." 2 Tr 109.

The ALJ found GLREA's arguments unpersuasive. He stated that "[i]t bears emphasizing that pursuant to MCL 460.1061, VGP programs are optional and VGP customers are required to pay all costs for the program, such that non-participating customers are not subsidizing VGP customers." PFD, p. 79.

Next, Consumers proposed to expand its Solar Gardens Community Solar Program by constructing, owning, and operating an incremental 5.5 MW of solar facilities. The company stated that:

> [t]his expansion is projected based on proxy facilities with a net capacity factor of 24%, capital costs of approximately $15 million, and a levelized cost of approximately $98/MWh. The filing assumes the Solar Gardens expansion will consist of 2.5 MW in 2026 and additional 3.0 MW in 2030. All of the Solar Gardens expansion is expected to qualify for 100% PTCs [production tax credits] and to be ultimately fully subscribed.

2 Tr 181.

GLREA objected to Consumers' proposed expansion of the Solar Gardens Community Solar Program, asserting that the program is "a far worse deal for residential customers" than what the company offers industrial customers. 4 Tr 621. GLREA argued that instead of expanding the Solar Gardens program, the company should implement community solar projects to allow customers to receive similar pricing as VGP customers.

Consumers responded, stating that it is not requesting to expand the Solar Gardens program. Rather, the company contended that it "has existing renewable energy assets of 4.5 MW currently in operation under the Pilot Solar Gardens Program which has a cap of 10 MW." 2 Tr 116. Consumers stated that the Pilot Solar Gardens program is 99.8% subscribed and the company is proposing to increase the solar capacity by 5.5 MW to the 10 MW cap by 2030. Consumers asserted that the Solar Gardens program is a voluntary program for customers and noted that there is an alternative program if customers are seeking a lower cost subscription.

The ALJ stated that, "[a]s was the case with the REP VGP concerns discussed above, GLREA appears to have a basic misunderstanding of how the Company's VGP programs for residential customers currently operate. As such, this PFD finds that GLREA's general concerns with the structure of the Solar Gardens program should be dismissed." PFD, p. 80.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

a. Voluntary Green Pricing Credits

GLREA noted that it proposed changes to the VGP program credits but acknowledged the Staff's "well-founded rebuttal in response." GLREA's initial brief, p. 17. However, GLREA requested that the Commission order a workgroup to determine if interested parties can reach common ground regarding VGP charges and credits.

Consumers objected to GLREA's request to modify the company's VGP program credits in this case, asserting that the VGP credits should be reviewed in Consumers' biannual VGP case in the fall. The company stated that "[t]his issue is not relevant to the Company's Amended RE Plan. Moreover, it is unclear as to why a workgroup should be established to discuss and evaluate the various options for the structure of VGP pricing in the future." Consumers' initial brief, p. 44 (citing 2 Tr 114); *see also*, Consumers' reply brief, p. 9.

The ALJ agreed with Consumers that VGP program charges and credits are properly addressed in the company's next VGP biannual filing. In addition, the ALJ stated that he "agree[d] with Consumers that programmatic and pricing provisions for VGP programs are 'unique to that electric provider and should be addressed in their own dedicated VGP proceedings' and not as part of a workgroup process." PFD, p. 81 (quoting Consumers' initial brief, p. 44).

GLREA excepts, asserting that:

> [w]hile specific pricing is certainly specific to each electric provider, the pricing structure of the VGP program (which currently consists of a premium based on the cost of renewable energy, and two credits – one for energy and one for capacity) is common between electric providers and could be changed in a consistent manner across electric providers. GLREA's proposal provides for the Commission's approval of the structure and specific pricing in the energy provider-specific VGP cases. However, GLREA continues to recommend an industry-wide workshop process to focus upon common VGP pricing issues.

GLREA's exceptions, p. 25 (citing 4 Tr 588).

In reply, Consumers states that "it is unclear what benefit this industry-wide workgroup would provide. Each electric provider's VGP programs are unique to that provider. Any changes to these programs should be addressed in the provider's dedicated VGP proceeding." Consumers' replies to exceptions, p. 14.

The Commission finds persuasive the ALJ's recommendation that GLREA's request for a workgroup should be denied. As noted by the company, "[e]ach electric provider's VGP programs are unique to that electric provider and should be addressed in their own dedicated VGP proceedings." Consumers' initial brief, p. 44 . The Commission agrees and adopts the ALJ's recommendation.

b. Community Solar

GLREA argued that Consumers' REP should have addressed the issue of community solar. According to GLREA, "Community Solar, if done like Maine or Minnesota, could represent 800-1,000 MW of solar generation and therefore be a significant contribution to achieving the RPS at little or no cost to the company and will result in lower cost than presented in this REP." 4 Tr 614. In addition, GLREA recommended options for compensating community solar customers and suggested that the RECs be included as part of compliance with the RPS.

The ALJ noted that several witnesses responded to GLREA's recommendations, however he "agree[d] with Consumers' overarching argument that specific issues concerning VGP and community solar programming, cost, and credit structures should be addressed as part of Consumers['] next VGP filing later in 2025." PFD, pp. 81-82.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

8. Co-Located Energy Storage

a. Ownership of Energy Storage Resources

MEIU requested that the Commission condition approval of Consumers' request for *ex parte* approval of energy storage resources on the following: (1) the competitive procurement process must utilize an IA, (2) a 50/50 ownership split for third-party and company-owned resources, and (3) the implementation of a process to update the company's LCOE target to reflect prevailing market conditions and to reevaluate whether the LCOE is the most appropriate metric for establishing an energy storage cost threshold. *See*, 4 Tr 638. Although MEIU supported the idea that energy storage may provide significant value to the grid, MEIU expressed concern "that the magnitude of the amendments proposed is significant and warrants careful examination to avoid exposing ratepayers to unnecessary costs and risks while also fostering a competitive environment for project developers." 4 Tr 663. Additionally, MEIU contended that the company's proposal to only co-locate energy storage additions "with Company-owned renewable assets is unnecessarily restrictive and may preclude opportunities for savings from a broader competitive procurement of energy storage resources." 4 Tr 663.

MEIU also objected to Consumers' claim that it can only implement energy storage projects that share a point of interconnection with a company-owned renewable energy system because it would be too difficult to manage coordination of energy storage operations at a third-party-owned facility. MEIU stated that it:

> agree[s] that the Company may not be able to *require* any existing renewable project to simply add storage, particularly if the project is owned by a third party via a PPA. However, that does not preclude the Company from exploring the feasibility of this option with existing counterparties. It also does not preclude the Company from allowing existing third-party project owners to propose energy storage additions as part of a competitive solicitation process.

4 Tr 665 (emphasis in original). In addition, MEIU asserted that if the renewable energy facility and the energy storage facility are owned by the same third party, there would be no coordination issues, and cited the Century Oaks Energy Storage LLC tolling agreement as an example.

Furthermore, MEIU argued that Consumers should not limit the resource procurement process to surplus energy storage. MEIU contended that "even if the Commission authorizes the use of excess interconnection capacity for battery energy storage located at Company-owned renewable asset sites, this should not limit the Company's ability and obligation to pursue other energy storage options that may be more cost-competitive or advantageous for other reasons." 4 Tr 666. MEIU cited, for example, the retirement of D.E. Karn Units 3 and 4 and noted the opportunity to interconnect resources using the generator replacement process, which would be quick and economical. Although MEIU acknowledged that "the opportunity to optimally integrate energy storage is likely best evaluated through a comprehensive IRP process," MEIU asserted that Consumers' deployment of energy storage resources "should be available to both utility-owned and third-party resources, instead of being narrowly limited to Company-owned energy storage projects." 4 Tr 667.

In response to MEIU's recommendation that Consumers expand opportunities for procurement of third-party-owned energy storage projects, the company generally agreed, noting that it has already contracted for 400 MW of battery energy storage systems (BESSs). Consumers stated that it also "will be considering hybrid projects as part of its Independent Auditor ("IA") led solicitations." 2 Tr 89. However, the company asserted that contracting for third-party BESSs at a company-owned renewable energy resource site or owning BESSs at a third-party renewable energy resource site would be ineffective and suboptimal because Consumers lacks the ability to manage the third-party system and select the lowest cost renewable energy resources.

Consumers also objected to MEIU's request that the company's competitive procurement process include an IA. According to the company:

> [a]n IA is appropriate in situations where the Company needs to fairly compare products or services it is proposing to provide with similar products or services that can be procured from a third party. The Company does not manufacture BESS components and does not perform construction activities with its direct workforce; therefore, it is not offering these services into a competitive solicitation and an IA would result in needless expense while providing no value to customers.

2 Tr 234.

Additionally, Consumers disagreed with MEIU's proposed 50/50 ownership split for energy storage resources. The company asserted that all of the proposed energy storage is co-located, hybrid, or surplus. Consumers explained that:

> [c]o-located, hybrid, and surplus energy storage is installed at existing interconnections owned by the Company. It is the Company's understanding of MISO's rules that the surplus interconnection agreement can only be entered into with the Interconnection Customer from the primary Interconnection Agreement. It is the understanding of the Company that MISO does not allow multiple interconnection customer parties to a single Interconnection Agreement, so a third-party interconnection customer could not interconnect under the Company's Interconnection Agreement. Furthermore, surplus interconnections are unique and are forfeited when the existing Interconnection Agreement is terminated. The dependency of the surplus interconnection agreement on the existing renewable energy interconnection agreements creates many complexities, making it infeasible for third parties to own and operate BESS facilities that rely on Company-owned interconnections as proposed in this RE Plan.

2 Tr 234. Moreover, the company stated that the LCOE is the standard by which Consumers compares projects. Although the company is not opposed to considering other metrics, Consumers asserted that it does "not expect a different metric to result in a materially different recommendation of one or another project." 2 Tr 235.

Regarding MEIU's proposal of a 50/50 ownership split of energy storage resources, the Staff contended that it may not be necessary to require a strict 50/50 split but asserted that 100% company ownership would not be prudent. The Staff stated that:

> in light of the significant costs associated with activities necessary to meet the requirements of [Act] 235, Staff's opinion is that the Company should be choosing the most economical and valid resources that meet its requirements, regardless of whether they are third-party or Company-owned. Staff would not support the Company entering into PPAs that are more costly than Company-owned resources, or vice versa, for the sole purpose of meeting a 50/50 requirement. Likewise, Staff also expects any Company-owned project, that successfully wins in a competitive request for proposal process (RFP), to be built for the cost that it was bid at and continues to monitor the actual costs of Company-owned projects through annual renewable reconciliations. Projects should be chosen primarily on economic merit, but should also consider other components, such as ability to meet timelines, risk associated with the project, financial stability of contractor, etc., as these all can ultimately result in additional costs for rate payers.

4 Tr 809-810. The Staff also contended that it will be necessary for Consumers to include third-party PPAs in all future RFPs to meet the aggressive portfolio standards set forth in Act 235.

MEIU opined that Consumers improperly asserts that the company will own all storage resources procured under the amended REP. Specifically, MEIU noted that the company argues that an IA is unnecessary because Consumers is only procuring BESS components or engineering, procurement, or construction services. Rather, MEIU asserted that an IA is necessary "to fairly compare products or services" because MEIU "is advocating for third-party ownership of storage resources." *See*, MEIU's initial brief, p. 21 (quoting 2 Tr 234).

In addition, MEIU disputed Consumers' claim that it would not be prudent for the company to contract for third-party BESSs at a company-owned renewable energy site or to own BESSs at a third-party renewable energy resource site. MEIU asserted that the company appears to conclude that third-party BESSs must be co-located with Consumers' existing renewable energy resources or that company-owned BESSs must be co-located with a third party's existing renewable energy resource, both of which are not manageable for Consumers. However, MEIU contended that Consumers':

> objections alleging insurmountable operational difficulties are clearly answered by a scenario in which storage procurement opportunities are opened to third parties

> already currently operating renewable energy resources under a PPA with the Company. The Company has provided no reason why it expects that third parties operating renewable energy resources would not have the same surplus interconnection rights or opportunities that it asserts access to via its owned resources.

MEIU's initial brief, p. 23.

MEIU also disagreed with Consumers' claim that a 50/50 ownership split of energy storage resources will limit the company's ability to procure the lowest cost storage resources. MEIU contended that "witness McDonnell's testimony shows that the empirical likelihood that a well-designed ownership split would end up compelling the Company to acquire uneconomic/uncompetitive third-party BESS[s] is very low." *Id*., p. 24.

The ALJ stated that "[f]or reasons already discussed, this PFD recommends rejection of a 50/50 ownership requirement, or any of MEIU's other recommendations, should the Commission include co-located storage as a renewable resource in this REP." PFD, p. 87.

MEIU objects, asserting that the PFD "fails to address or otherwise engage with MEIU's broader arguments regarding third-party ownership of co-located storage, and its apparent rejection of MEIU's recommendation that the opportunity to provide co-located storage be available to third parties and not just the Company is at odds with the PFD's recommendations with respect to wind resources." MEIU's exceptions, p. 7. MEIU notes that the ALJ found that Consumers' proposed 100% ownership of wind resources may prevent healthy competition and cost-effective projects. MEIU opines that, "[i]f this is the case with wind resources, it is hard to imagine why it would not also be the case with co-located storage resources, and the PFD certainly provides no reasons to make such a distinction." *Id*., pp. 7-8. MEIU requests that the Commission consider MEIU's arguments regarding third-party ownership of co-located energy storage acquired through the company's REP, opportunities for third-party-owned co-located energy storage, and a target 50/50 ownership split.

Similar to the Commission's conclusion in the "Company-Owned Wind Energy Resources" section above, the Commission finds that 100% company-ownership of energy storage resource assets is not reasonable because it impedes healthy competition and may result in Consumers' acquisition of expensive assets. However, the Commission finds it imprudent to order an explicit 50/50 ownership split. Rather, the Commission finds that Consumers should implement a competitive bidding process for energy storage resources and should actively solicit third-party PPAs in all its future RFPs in order to select the most feasible and economical projects regardless of ownership. The Commission agrees with MEIU that the company should use an IA in its competitive bidding process, and as noted above, plans to review the competitive procurement guidelines in the near future to, in part, address concerns raised by MEIU.

MEIU requested that the Commission implement a process to update the company's LCOE target and reevaluate whether the LCOE is the most appropriate metric for establishing an energy storage cost threshold. In the "*Ex Parte* Approval and 140% Levelized Cost of Energy Multiplier" section above, the Commission found that Consumers' wind and solar LCOE targets should be regularly updated in the company's subsequent REP amendments.

b. Energy Storage Cost Recovery

Consumers asserted that energy storage should be included in the amended REP because it provides value, such as energy, capacity, ancillary services, transmission, and distribution benefits. In addition, the company contended that energy storage helps to enable renewable energy—i.e., it reduces curtailment of renewable generation assets and increases the utilization of renewable energy infrastructure. Consumers stated that, "most importantly, off-peak renewable energy that is stored and used during on-peak hours yields IRECs [incentive renewable energy credits] which will be used to demonstrate REC Portfolio Standard compliance which is the key objective of the Company's RE Plan." 2 Tr 217; *see also*, Consumers' initial brief, pp. 46-47. The company asserted that it plans to pursue energy storage projects only if they share a point of interconnection with a renewable energy system.

Consumers projected an LCOE of $143.54/MWh for energy storage resources with a COD of January 1, 2028. According to the company, "[t]his cost is based on the costs from the recently executed Power Purchase Agreement with Century Oaks Energy Storage LLC that has been reviewed and approved by the [Commission] in Case No. U-21090." 2 Tr 218. Consumers used the costs from Case No. U-21090 as a target for energy storage projects in the amended REP and proposed to recover all costs of energy storage projects through the REP cost of compliance.

The Staff expressed several concerns regarding the company's proposed cost recovery for co-located energy storage projects: (1) "storage is not listed under 'renewable energy resource' at MCL 460.1011(g);" (2) "only renewable energy resources are included in the renewable energy cost recovery mechanism first established in Public Act 295 of 2008 (PA 295), as amended by Public Act 342 of 2016 (PA 342) and mostly maintained in PA 235;" and (3) MCL 460.1022(3) states that an amended REP must include a forecast of renewable energy resources needed to comply with the RPS, and energy storage is not listed in the definition of "renewable energy resource" in MCL 460.1011(g). 4 Tr 792-793.

The Staff noted that energy storage is mentioned in MCL 460.1039(2)(c), which discusses incentive RECs for renewable energy electricity generated during off-peak hours and stored in an energy storage system. The Staff asserted that MCL 460.1101(4) states that a utility may recover the costs of contracts for eligible energy storage in the utility's base rates. Therefore, the Staff stated that:

> [b]eing that storage was clearly mentioned in the same statute as a means to create incentive credits and that established a 2,500 MW storage target but also did not define it as a renewable energy system or specifically state it should utilize the renewable cost recovery mechanism, Staff submits that the most obvious solution is that storage assets should be recovered in base rates, through a general rate case.

4 Tr 793-794.

The Staff contended that cost recovery remains the same even if the energy storage system is co-located with a renewable energy asset. The Staff stated that "tying cost recovery of a co-located storage facility to that of the traditionally defined renewable energy resource it is co-located with could result in inefficient operation of that storage asset" because:

> [i]f the storage asset where [sic] to be connected to the Direct Current (DC) side of the renewable asset point of interconnection (POI) and only charge from the renewable energy resource that it is co-located with in an effort to effectively call it a single resource for purposes of cost recovery, as opposed to charging directly from the distribution or transmission grid, it would mean that charging would be limited to the intermittent generation of the renewable energy system. Regardless of whether the storage is on the DC side or connected to the Alternating Current (AC) side of the renewable asset POI, the Company can still allocate costs to each of the assets even if they share components within the common POI.

4 Tr 794 (footnote omitted). Thus, the Staff recommended that Consumers install energy storage assets to allow it to optimize charging using both a shared interconnected asset and/or the grid. The Staff argued that, without this configuration, the value of energy storage to the broader grid is diminished.

In response to the Staff's claim that the costs of energy storage must be recovered through base rates, Consumers disagreed, asserting that the costs can be recovered as an ICOC in the REP pursuant to MCL 460.1047(2)(a)(vii). The company also disagreed with the Staff's assertion that a co-located storage facility with a traditional renewable energy source may result in the inefficient operation of storage assets. Consumers stated that:

> [a]n energy storage asset is typically designed to discharge over 4 hours and charge over the same period. This would allow, under normal operations, the energy storage asset to charge and discharge once a day without impact to a solar asset and only minor impact from full production of a wind asset (a co-located energy storage asset with wind will not be able to charge/discharge every day due to the nature of wind generation).

2 Tr 228. Consumers also contended that energy storage assets are sited to best utilize the interconnection facilities and to best use the traditional renewable energy asset, which is accomplished by "optimizing the sizing of the energy storage to maximize energy, capacity, and renewable energy credit values for a given project." 2 Tr 228. By optimizing the energy storage asset, the company averred that the asset will serve as an enabler to improve the functionality of the traditional renewable generation asset and will not impede the efficiency of the energy storage facility.

Responding to the Staff's claim that an energy storage system is not a renewable energy resource under Act 235, the company noted that MCL 460.1011(i) defines "renewable energy systems" as a "facility, electricity generation system, or set of electricity generation systems that use 1 or more renewable energy resources to generate electricity or steam." Consumers' initial brief, p. 46 (quoting MCL 460.1011(i)). Consumers argued that "[a]n energy storage system charged from a renewable resource falls within the definition of a 'renewable energy system' because it is a facility that uses '1 or more renewable resources to generate electricity or steam.'" *Id*. For example, the company explained that if a co-located energy storage system is charged by a renewable energy resource, such as a solar PV facility, and the energy storage system injects the generated and stored energy into the transmission or distribution system:

> whether the energy is being provided to the grid directly from the solar PV facility or from the energy storage system that has been charged from the solar PV facility, the energy is being generated from "solar and solar thermal energy," which are renewable energy resources under MCL 460.1011(g)(ii). In addition, energy storage resources are not listed as one of the exclusions from the definition of "renewable energy systems" under MCL 460.1011(j).

Consumers' initial brief, p. 47.

In addition, the company contended that MCL 460.1101(4) does not prohibit recovery of co-located energy-storage resource costs through the REP. Consumers explained that MCL 460.1101(1) "requires an electric provider to 'construct or acquire eligible energy storage systems or enter into eligible energy storage contracts to meet its share of a statewide energy storage target of a combined capacity of at least 2,500 MW.'" Consumers' initial brief, p. 47 (quoting MCL 460.1101(1)). Then, the company noted that MCL 460.1101(4) states that:

> a rate-regulated electric provider "shall submit to the commission for review and approval eligible energy storage contracts entered into to meet its share of the statewide storage target," and if the Commission approves the eligible energy storage contracts, the Commission must "authorize the electric provider to recover the costs of the contract in the electric provider's base rates."

Id. (quoting MCL 460.1101(4)).

Next, Consumers stated that pursuant to MCL 460.1101(9)(b), an "eligible energy storage system" is an "an energy storage system that is located within the local resource zone or the locational deliverability area, as defined by the appropriate independent system operator or regional transmission organization, in which the electric provider is subject to capacity demonstration obligations pursuant to section 6w(8)(b) of 1939 PA 3, MCL 460.6w." *Id*. (quoting MCL 460.1101(9)(b)). Consumers contended that pursuant to the above statutory provisions:

> the statewide storage target storage systems are not limited to those systems that are co-located with renewable energy resources, and the Company plans to meet its share of the statewide energy storage target excluding co-located storage. So while MCL 460.1101 requires the Commission to authorize the recovery of eligible energy storage contract costs in base rates where those contracts are meant to

> support the statewide storage target, this does not prevent the recovery in the RE Plan of co-located energy storage resources that support meeting the REC standard by reducing renewable energy curtailment, avoiding energy waste, and supporting the creation of additional RECs and incentive RECs.

Consumers' initial brief, pp. 47-48 (citing 2 Tr 91).

The Staff disagreed, asserting that if the Legislature intended to consider energy storage resources as a renewable energy system and allow cost recovery of these assets under the cost recovery mechanism in MCL 460.1047 and 460.1049, the Legislature would have explicitly included energy storage resources in the definition of "renewable energy resources" in MCL 460.1011(g). Additionally, the Staff stated that it "is not convinced by the argument that co-located storage increases the quality and reliability of renewable energy. It simply allows it to be stored when not needed on the grid." Staff's initial brief, p. 4. The Staff asserted that the company failed to provide a clear explanation of what it considers to be co-located. In any event, the Staff argued that "[DC] coupled storage with renewable energy would not allow the storage to be optimally utilized to provide benefit to the grid as a whole. Thus, recovery of co-located storage should not be approved in this plan case; rather, it should be approved in base rates." *Id*.

The ALJ agreed with the Staff that the costs for energy storage, including co-located energy storage, should be recovered in base rates. He stated that:

> Act 235 speaks directly to the issue of cost recovery of energy storage at MCL 460.1101(4). The statute uses the word "shall" and therefore indicates a mandatory directive. The language of MCL 460.1101(4) is clear and unambiguous and reflects the Legislature's intent that energy storage costs should be recovered in base rates. Consumers' arguments that subsection 4 only refers to contracts for energy storage that are used to meet Act 235's energy storage goals are unavailing.

PFD, pp. 92-93 (footnotes omitted).

The ALJ also disagreed with Consumers' claim that because a co-located energy storage facility uses one or more renewable energy resource to generate electricity or steam it is a renewable energy system pursuant to MCL 46.1011(i). He opined that "[e]nergy storage does not generate electricity, rather it is a technology that absorbs, stores, and releases energy." PFD, p. 93 (citing MCL 460.1005(i), 460.1221(j), and 460.1039(2)(c)). Similarly, the ALJ found "[t]he Company's point that energy storage resources are not listed as one of the exclusions from the definition of 'renewable energy system' under MCL 460.1011(j) is dispatched under the doctrine *Inclusio Unius Est Exclusio Alterius*: since co-located energy storage is not mentioned in the list of exclusions, it is implied that the Legislature did not intend to exclude it." *Id*.

Moreover, the ALJ disputed Consumers' claim that co-located energy storage resource costs may be recovered through the REP. He stated that, pursuant to MCL 460.1047, co-located energy storage resource costs are optional and not "necessarily incurred" to ensure the quality and reliability of renewable energy required to meet the RPS. PFD, p. 93 (citing MCL 460.1047(2)(a)(iv)).

Finally, the ALJ declined to recommend approval of the Staff's request that Consumers install energy storage assets in a manner that will allow the company to optimize charging using both the shared interconnection asset and/or the grid. He stated that "such a directive [is] unnecessary at this time since the Company asserts that its energy storage assets are optimized to maximize energy and capacity. While the Company also states that it optimizes its energy storage to maximize renewable energy credit values for a given project, it is unclear how this would impact the efficiency of the storage asset." PFD, p. 94.

In exceptions, Consumers states that "[w]hile the Company continues to believe that its proposal to include co-located storage costs as part of future [REP] costs of compliance is consistent with applicable law as explained in the Company's Initial Brief and Reply Brief, the Company withdraws its request in this case for Commission authorization to include co-located energy storage in the [REP].” Consumers’ exceptions, p. 8; *see also*, Consumers’ replies to exceptions, p. 15.

In light of Consumers’ withdrawal of its request for cost recovery for co-located energy storage projects, the Commission finds that the company shall reflect this change in subsequent biannual amended REP filings and its 2025 REP reconciliation.

9. Financial Compensation Mechanism

Consumers stated that its REP includes the recovery of FCM costs through the PSCR mechanism, which is authorized by MCL 460.1047(2)(a)(v)(C), for all contracted renewable energy resources executed after June 30, 2024, pursuant to MCL 460.1028(8). In addition, the company noted that MCL 460.1047(2)(a)(i) states that the electric provider’s authorized rate of return on renewable energy resources be used to comply with the renewable energy standard. Specifically, Consumers asserted that its “FCM is calculated using the pre-tax weighted average cost of permanent capital, as set forth in MCL 460.1028(8), to annual contract payments. Recovery of FCM costs related to eligible contracts will be included in Consumers Energy’s PSCR mechanism.” Consumers’ initial brief, p. 51 (citing 2 Tr 48, 81).

The Attorney General noted that in Case No. U-20165, an FCM was proposed to address an issue with PPAs that was identified by Consumers. She stated that the FCM established in Case No. U-20165 was included in the settlement agreement in Case No. U-21090 and approved by the June 23 order with the following modifications: (1) the FCM would be extended at the after-tax weighted average cost of capital (WACC) of 5.62% and updated in electric rate case orders; (2) the FCM was approved for all new PPAs but not PPA amendments, PURPA PPAs, VGP PPAs, or a PPA executed under the REP; and (3) the FCM would be subject to price caps. *See*, 2 Tr 462-463. Therefore, the Attorney General argued that, pursuant to the terms of the settlement approved by the June 23 order, the company may not recover FCM costs for contracts executed under the REP, as is proposed in this case. In addition, she requested that the Commission direct Consumers "to not include an FCM for any new PPA contract attached to future renewable energy projects required to meet its VGP and RE Plan requirements." 2 Tr 469; *see also*, Attorney General's initial brief, pp. 38-41.

The company acknowledged that in Case No. U-21090, it "agreed to not apply the IRP FCM to PPAs entered into under the RE Plan," however Consumers argued that "[t]he enactment of Act 235 changed the statutory framework" and it now authorizes an FCM for a rate-regulated electric provider that is limited to PPAs for renewable energy resources or third-party contracts for energy storage systems or clean energy systems with non-affiliated companies. Consumers' initial brief, p. 52. The company asserted that "contrary to the contention of the Attorney General, the FCM calculation is not limited to the Company's prevailing WACC, and the Company's eligibility is not subject to Commission discretion. Thus, the Company's FCM should be authorized." *Id*.

The ALJ agreed with Consumers that the Attorney General's argument should be rejected. He noted that:

> [w]hile Consumers did previously agree pursuant to the settlement agreement that the FCM would not apply to any PPA's executed under the REP, among other restrictions, Consumers' agreement was made in the context of a second contested case challenging whether Consumers should have any FCM, which case was prosecuted when the applicable statute provided that the Commission had the discretion to either approve or not approve an FCM. Clearly, Consumers would not agree to the limited settlement FCM terms approved in the prior IRP cases today when all of the FCM terms under the revised statutes were available to it without any contest.

PFD, pp. 96-97. In addition, the ALJ noted that Act 235 states that the provisions of the act "'appl[y] to any contract entered into after June 30, 2024'." *Id*., p. 97 (quoting MCL 460.1028(8)).

ABATE noted that, for non-VGP renewable energy PPA contracts that the company executed prior to June 30, 2024, but are eligible for an FCM through prior Commission orders, Consumers recovers the contract price through the PSCR mechanism and the FCM costs through a surcharge. However, ABATE stated, for renewable energy resources contracts entered after June 30, 2024, the company proposes to recover the contract costs and the FCM costs through the PSCR mechanism. ABATE contended that Consumers has not provided an explanation for this change. Moreover, ABATE argued that:

> this change would reduce transparency for ratepayers relative to the current FCM surcharge method. Transparency into the rate impact of the FCM should be maintained, particularly as the amount of the FCM is projected to increase significantly in future years. In addition, the Company has not explained its intention regarding the allocation of the FCM if it is recovered through the PSCR.

4 Tr 725.

In response, Consumers asserted that it evaluated several options for recovering FCM costs and, because one of the goals of the amended REP is to avoid implementation of a revenue recovery mechanism, the company determined that it would be prudent to recover FCM costs through the PSCR mechanism. Additionally, Consumers contended that it appears that "[ABATE] is recommending the FCM that is authorized pursuant to MCL 460.1028(8) be recovered through the methodology established for the prior FCM mechanism resulting from the 2016 energy laws." 2 Tr 80. The company argued that the previous Commission-established FCM methodology is not appropriate for the newly established FCM in Act 235 because it would result in a significant increase in the surcharge and carrying charges.

Consumers also objected to combining the two FCM methodologies because:

> [t]he calculation methodology and resource type applicability for each of the FCMs are different. The existing FCM surcharge, established in Public Act 341 of 2016, was generally applicable to contracts established pursuant to the Company's IRPs and was capped at the Company's weighted average cost of capital ("WACC").

> Specifically, MCL 460.6t(15) allowed the Commission to **consider** and authorize a FCM which could not exceed the Company's WACC. Further, it was not limited to renewable energy resources, it was applicable to all PPAs with non-affiliated companies.

2 Tr 81 (emphasis in original).

However, the company agreed with ABATE's request that Consumers should allocate a portion of the FCM costs to capacity. Consumers stated that it "will allocate the FCM in the same manner that the underlying purchased power contract costs are allocated to energy and capacity. Currently 17% of purchased power costs are allocated to capacity." 2 Tr 81.

ABATE disputed the company's claim that the previous Commission-established FCM methodology is not appropriate for the FCM set forth in Act 235 because it will significantly increase surcharges and carrying charges. According to ABATE, "even if valid," these issues "do not justify revising the existing FCM collection approach." ABATE's reply brief, p. 2. In addition, ABATE asserted that Consumers' argument that the two FCMs are calculated differently is irrelevant. ABATE opined that:

> [w]hether or not the FCM for new renewable energy contracts is *calculated* differently from the current FCM makes no difference to the appropriateness of the current *collection method*. The FCM is still an incentive for entering into renewable energy contracts. A surcharge is therefore the most straightforward and transparent way of accounting for and collecting this "cost" to customers, which is unrelated to the actual power purchased through the renewable energy contract.

Id. (emphasis in original). Furthermore, ABATE reiterated that the company's proposed method for recovering FCM costs through the PSCR mechanism would reduce transparency and visibility regarding the REP and PPA costs that Consumers is collecting. ABATE contended that the volatility of uncertain projections and carrying charges for over- and undercollections are best addressed through a separate surcharge. *Id*.

The ALJ agreed with ABATE that "the FCM is still an incentive for entering into renewable energy contracts, and that a surcharge is the most straightforward and transparent way of accounting for and collecting this cost to customers, which is unrelated to the actual power purchased through the renewable energy contract." PFD, p. 99 (quoting ABATE's reply brief, p. 2). In addition, he found ABATE's argument persuasive that Consumers' proposed method for recovering FCM costs through the PSCR mechanism would provide less transparency for ratepayers. Therefore, the ALJ recommended that the Commission reject Consumers' proposal and require the company to recover FCM costs through a surcharge.

Consumers excepts, arguing that it is unclear from the ALJ's recommendation whether FCM costs should be recovered through the revenue recovery mechanism or the existing FCM surcharge. In any event, the company contends that both are improper. First, Consumers asserts that "recovery through the revenue recovery mechanism is inappropriate as one was not proposed in this case. No party objected to the Company's proposal not to implement such a mechanism. Nor did any party argue that it would be appropriate to delay recovery of the FCM." Consumers' exceptions, p. 8. Second, Consumers reiterates that it would not be appropriate to combine the new FCM with the existing FCM surcharge because the methodologies are different and it would lead to a significant increase in the surcharge based on uncertain projections and carrying charges for over- and undercollections. *See*, Consumers' exceptions, pp. 8-9 (citing 2 Tr 80-81). The company contends that "[t]he FCM is a cost of the renewable energy contract" and "[i]nclusion of this cost in the PSCR will ensure that it is recovered by the customers receiving the power." Consumers' exceptions, p. 9.

ABATE disagrees that the ALJ's recommendation was unclear. ABATE states that:

> the ALJ expressly identifies ABATE's recommendation to collect the FCM through the "existing FCM surcharge." The ALJ goes on to state that he "agrees with

> ABATE that the FCM is still an incentive for entering into renewable energy contracts, and that a surcharge is the most straightforward and transparent way of accounting for and collecting this cost to customers." He concludes by saying "this PFD recommends that the Commission should therefore reject Consumers' proposal and require that Consumers' FCM continue to be recovered through the surcharge."

ABATE's replies to exceptions, p. 2 (quoting the PFD, pp. 97, 99) (emphasis added by ABATE). ABATE contends that the only surcharge identified by the ALJ is the existing FCM surcharge and he recommended that FCM costs continue to be recovered through the surcharge.

ABATE also disputes Consumers' claim that the ALJ recommended that FCM costs be recovered in a revenue recovery mechanism—specifically the renewable energy surcharge. ABATE states that "[i]f Consumers' FCM were recovered in the renewable energy surcharge, then that would entirely defeat the reason behind the judge's recommendation. Specifically, the judge was persuaded that the FCM should be collected in a separate surcharge because it 'is the most straightforward and transparent way of accounting for and collecting this cost to customers.'" ABATE's replies to exceptions, pp. 2-3 (quoting the PFD, p. 99). According to ABATE, if the FCM were recovered through the renewable energy surcharge, there would be no transparency because the FCM cost would be comingled with other costs. Therefore, ABATE contends that the ALJ would not have recommended recovery of the FCM through the renewable energy surcharge.

Furthermore, ABATE disagrees with Consumers that if FCM costs are recovered separately from the renewable energy PPA cost, then the FCM will be an ICOC pursuant to Act 235 and should be recovered through the renewable energy surcharge. ABATE does not dispute that both the renewable energy PPA costs and associated FCM are costs that may be included in the ICOC calculation. However, ABATE asserts that "[i]f the Commission directs Consumers to recover the FCM in a FCM surcharge separate from the associated PPA costs, then there would still be no incremental costs of compliance for Consumers. The PPA costs would be offset by PSCR revenues and the FCM costs would be offset by the FCM surcharge revenues." ABATE's replies to exceptions, p. 4. Thus, ABATE contends, there is no need for a renewable energy surcharge.

The Commission finds that the ALJ's recommendation should be adopted, in part. The Commission agrees with the ALJ that the terms of the settlement agreement approved by the June 23 order do not preclude Consumers from requesting recovery of FCM costs in this case. The settlement agreement in Case No. U-21090 was executed pursuant to the provisions of Act 341, under which an FCM was permitted, but approval was subject to the Commission's discretion. Act 235 was enacted after the settlement agreement was executed in Case No. U-21090 and after the June 23 order was issued, and Act 235 changed the statutory framework of Act 341. Act 235 expressly authorizes an FCM for rate-regulated providers and the eligibility of the rate-regulated provider to request an FCM is not subject to the Commission's discretion. In addition, as noted by the ALJ, "Consumers would not agree to the limited settlement FCM terms approved in the prior IRP cases today when all of the FCM terms under the revised statutes were available to it without any contest." PFD, p. 97. Therefore, the Commission agrees with the ALJ that the Attorney General's argument on this point should be rejected.

However, the Commission respectfully declines to adopt the ALJ's recommendation to approve ABATE's proposed recovery of the FCM costs through the FCM surcharge. ABATE contended that under the current FCM surcharge methodology, the capacity and energy components of the FCM are allocated using the 4 Coincident Peak 75/0/25 allocator and should continue to be allocated as such. As noted by Consumers, it appears that ABATE's recommended recovery method is based on the methodology established pursuant to the 2016 energy laws, rather than Act 235. Section 28(8) of Act 235 directs the Commission to authorize an FCM for a rate-regulated electric provider who enters into a PPA for renewable energy resources or a third-party contract for an energy storage system or clean energy storage system with a utility that is not an affiliate for any contract entered after June 30, 2024. *See*, MCL 460.1028(8). Accordingly, the Commission finds persuasive Consumers' argument that "the FCM is a cost of the renewable energy contract" and, therefore, it should be recovered through the PSCR mechanism. 2 Tr 80. In addition, the Commission finds that ABATE failed to sufficiently rebut Consumers' argument that ABATE's proposed recovery of FCM costs through the current FCM surcharge would significantly increase the surcharge because of "uncertain projections and carrying charges for both over-collections and under-collections." 2 Tr 80.

10. Approval of Solar Contracts

Consumers noted that in Case No. U-21585, the company requested recovery of capital expenditures for the Mustang Mile, Washtenaw, Muskegon, and Spring Creek solar projects; however, after an agreement between the Staff and Consumers, the Commission approved removal of the capital expenditures from Case No. U-21585 and directed the company to seek recovery for the projects in Consumers' next REP case, which is the immediate case.

In this case, Consumers stated that the Mustang Mile Solar Project:

> is a 150 MW solar facility located in Macon Township, Lenawee County, Michigan. The project will be connected to the METC [Michigan Electric Transmission Company] 138 kV transmission system in accordance with the terms and conditions outlined in the MISO GIA, executed on August 6, 2020. All required land rights for the project have been secured and a special land use permit has been granted; however, legal challenges to the permit are currently being litigated which is preventing the completion of the project. While the Company expects that the opposition groups will ultimately fail in their legal challenge, the project has been delayed because of these challenges [and] therefore a revision to the original project schedule is required. The unpredictable duration of the legal issues makes it difficult to assume an accurate revised COD at this time.

2 Tr 224-225. The company asserted that it is working with Invenergy on a revised schedule and cost for the project, which will be presented to the Commission for approval. 2 Tr 225.

The company explained that the Washtenaw Solar Project:

> is a 150 MW solar facility located in Saline Township, Washtenaw County, Michigan. The project will be interconnected with the International Transmission Company's 345 kV transmission system in accordance with the terms and conditions outlined in its MISO GIA, executed April 23, 2021. The project has secured land rights for more than 1,100 acres, but due to changes to Saline Township zoning ordinances enacted after the execution of the BTA, the project will require additional land rights in order to be sited locally or will need to rely on the recently passed state certification process.

2 Tr 223-224. The company asserted that it is working with Invenergy on a revised schedule and cost for the project, which will be presented to the Commission for approval.

The Attorney General objected to including costs for the Mustang Mile and Washtenaw solar projects in the company's REP. She explained that both projects "currently do not have expected commercial operation dates due to significant delays these projects have experienced related to ligation and regulatory delays in obtaining permits needed to commence construction." 2 Tr 453. Specifically, the Attorney General noted that in Consumers' electric rate case, the company could not provide an accurate COD for Mustang Mile and conceded that Washtenaw would not be in operation until late 2027. In addition, she stated that in discovery in this case, Consumers could not provide an update on the status of the Washtenaw project. The Attorney General contended that "[t]hese projects can be included in future amended RE Plans once greater certainty is known regarding the viability of these projects and anticipated COD." 2 Tr 456. Furthermore, she recommended that the Commission direct the company to identify replacement RECs for these projects until plans for the projects are more concrete.

Consumers disagreed with the Attorney General, asserting that it is required to include in its REP: (1) "a forecast of the renewable energy resources needed to comply with the renewable energy credit standard pursuant to a filing schedule established by the commission," (2) a "mechanism for the recovery of the incremental costs of compliance," and (3) costs associated with the "renewable energy portfolio established to achieve compliance with the renewable energy standards." Consumers' initial brief, p. 55 (quoting MCL 460.1022(2) and (3); MCL 460.1047(2)(a)(i)). Accordingly, the company stated that it included the Mustang Mile and the Washtenaw solar projects in its REP as renewable energy resources that comply with the RPS.

Consumers noted that the Mustang Mile and Washtenaw BTA were both approved in Case No. U-20165, and although there is some uncertainty with the COD for the projects, both "are the result of competitive solicitations that were conducted pursuant to a Commission-approved IRP." Consumers' initial brief, p. 55 (citing 2 Tr 229). In addition, the company contended that by including the projects in the REP, it is acknowledging that the projects will be used as resources to meet the RPS and that the costs will flow through to the REP reconciliation case. In Consumers' opinion, "[t]he uncertainty of the COD has no bearing on the appropriateness of including the projects within this RE Plan. All renewable energy projects face schedule risk, and these two specific projects have realized that risk." 2 Tr 229.

Furthermore, the company argued that there is no present cost to customers by including the Mustang Mile and the Washtenaw solar projects in the REP. By contrast, Consumers stated, the REP would be significantly more inaccurate if the Mustang Mile and Washtenaw solar projects are excluded, asserting that "[b]oth the costs of compliance and PSCR transfer costs would be dramatically under-projected as a result of excluding these in-development projects." 2 Tr 193.

The ALJ agreed with the Attorney General that the Mustang Mile and Washtenaw solar projects should be excluded from the REP. He noted that "Consumers acknowledges the delays and uncertainty associated with these two projects and while it believes that the challenges to these projects will be resolved favorably, any such resolutions are unclear at this time." PFD, p. 104. Therefore, the ALJ recommended that the Commission exclude from the REP the costs for the

Mustang Mile and Washtenaw solar projects and direct the company to identify replacement RECs for the projects.

Consumers objects to the ALJ's recommendation, explaining that:

> [i]f the projected costs for Mustang Mile and Washtenaw are excluded from the Amended RE Plan, then the projected cost of compliance would be incomplete, which would then make the Company's regulatory balance projections inaccurate. The Company's plan will also be insufficient to achieve compliance with the REC Standard. Removal of these projects from the Amended RE Plan would result in under-projecting the costs of compliance and the PSCR transfer costs. Eliminating these projects, and their development costs, from the Amended RE Plan would create significant inaccuracies and variances between the Amended RE Plan and the annual reconciliations.

Consumers' exceptions, pp. 12-13 (citing 2 Tr 192-193, 195). In addition, the company disagrees with the ALJ's recommendation that Consumers identify replacement RECs for the Mustang Mile and Washtenaw solar projects. Consumers argues that "neither the PFD, nor any parties in this case, identified any more certain projects that the Company could substitute for the Mustang Mile and Washtenaw projects in this Amended RE Plan." Consumers' exceptions, p. 13. Finally, the company reiterates that there is no current customer rate impact for including the Mustang Mile and Washtenaw solar projects in the amended REP.

The Staff excepts, asserting that the Mustang Mile and Washtenaw solar projects should be included in the REP and that Consumers is entitled to cost recovery for the projects. The Staff states that the Commission has already approved these projects in Case No. U-20165 and "[i]n its March 2025 Order in Case No. U-21585, the Commission also agreed that [it] was reasonable for the Company to move these projects from the Company's general rate case to its Amended REP." Staff's exceptions, p. 2 (citing March 21, 2025 order in Case No. U-21585, p. 158). The Staff contends that if Consumers is required to identify additional RECs and the Mustang Mile and

Washtenaw projects then progress, the company will have procured unnecessary RECs and superfluous expense. *Id*., pp. 2-3.

In exceptions, GLREA notes that the Attorney General recommended that the Mustang Mile and Washtenaw solar projects be removed from the company's REP and that the Commission direct Consumers to identify replacement RECs for these projects. GLREA "proposes the use of DG outflow REC purchases as a readily available source of replacement RECs." GLREA's exceptions, p. 19.

The Attorney General disagrees with Consumers' claim that because the projects have been included in the REP, the projects are necessary to the plan. She states that the company disregards the standard in Act 235 that requires the Commission to evaluate whether the REP and the proposed costs are reasonable and prudent. The Attorney General asserts that "[g]iven this standard of review, the Company has failed to meet its burden of proof to show that inclusion of the Washtenaw and Mustang Mile projects in its RE Plan is reasonable and prudent. The preponderance of the evidence presented in this case highlights the uncertainty as to whether and when the two solar projects might actually be completed." Attorney General's replies to exceptions, p. 2 (footnote omitted).

The Attorney General also objects to the Staff argument that because the Mustang Mile and Washtenaw solar projects were included in Consumers' IRP, the cost of the projects may be recovered through the REP process. She states that the "Staff presents no authority to justify this conclusion, and nothing in the Commission's Order in Case U-21585 guaranteed cost recovery as part of this case. In fact, ***as noted in the Case U-21585 Order, Consumers explicitly addressed the possibility that it might not achieve recovery in this REP case, thus directly contradicting***

Staff's argument here . . . ." Attorney General's replies to exceptions, pp. 5-6 (emphasis in original).

The Commission finds persuasive Consumers' and the Staff's arguments that the Mustang Mile and Washtenaw solar projects should be included in the company's REP. As noted by Consumers and the Staff, the Commission approved the BTAs for these projects in Case No. U-20165, the Commission agreed that cost recovery for these projects should be removed from Case No. U-21585, and the Commission agreed in Case No. U-21585 that Consumers could include the projects in the immediate case. Additionally, the Commission finds persuasive Consumers' argument that if the two projects are excluded from the company's amended REP, "the costs of compliance and PSCR transfer costs would be dramatically under-projected" and Consumers' amended REP "will also be insufficient to achieve compliance with the REC Standard." 2 Tr 193; Consumers' exceptions, p. 12. Furthermore, the Commission agrees with Consumers and the Staff that if the projects are excluded and the company is directed to identify replacement RECs to comply with the RPS, no party has identified any more certain and/or less costly replacement projects. And, as noted by the Staff, if Consumers is directed to procure replacement RECs and the Mustang Mile and Washtenaw solar projects then move forward, the company will have procured needless RECs and additional unnecessary expense. Therefore, the Commission declines to adopt the ALJ's recommendation to approve the Attorney General's proposed exclusion of the projects from the company's amended REP and, instead, approves Consumers' request to include recovery of capital expenditures for these projects in this case.

11. Other Issues

a. Biomass Merchant Plant Resources

The BMPs asserted that Consumers' amended REP has serious flaws and does not comply with the requirements of MCL 460.1001, *et seq*., and the Commission's Filing Requirements for Renewable Energy Plans. The BMPs explained that the company's:

> [a]mended REP includes only intermittent, non-dispatchable solar generation with an assumed capacity factor of 23% and wind generation with a capacity factor of 29.0%. The assumed solar capacity factor of 23% is overstated and unsupported. Consumers' own generation data shows that the historic average capacity factors of its existing solar projects range between 18.1% and 21.2%. That virtually ensures that Consumers actual costs for the 8,000 MW of additional solar generation for which it has requested *Ex Parte* contract approval will exceed its stated Levelized Cost of Energy ("LCOE").

BMPs' initial brief, p. 1 (citing 2 Tr 60, 265; Exhibits BMP-5 and BMP-14). Further, the BMPs stated that if the company uses the 23% solar capacity factor, Consumers will be short 1.98 million RECs in 2040, resulting in only 55% compliance compared to the required 60%. The BMPs argued that, instead, Consumers' amended REP should include a mix of existing, indigenous Michigan renewable energy resources and non-intermittent, baseload dispatchable renewable generation that can be provided by the BMPs.

The BMPs stated that their baseload, continuous dispatchable energy can be provided 24/7, with an annual proven 93.0% availability factor and 100% capacity factor. More specifically, the BMPs contended that they:

> can provide this performance at costs equivalent or lower than any LCOE associated with combinations of renewable energy generation resource and energy storage combination Consumers has included in its Amended REP. ***The 183.17 MW of BMPs can replace 692 MW of solar capacity even using Consumers' overstated 23.0% solar capacity factor. They can replace approximately 776.4 MW of solar generation using the actual 20.5% solar capacity factor of Consumers existing solar facilities.*** In fact, no reasonable combination of renewable generation resources and energy storage proposed by Consumers in the Amended REP can provide the same 24/7 generation performance as the BMPs.

2 Tr 265 (emphasis in original). The BMPs also asserted that "Consumers has not entered into any discussions with the BMPs about the possibility of including their generation in the Amended REP beyond their current contract expiration dates," which the BMPs claim is contrary to the provisions of MCL 460.1001(2). 2 Tr 264 (citing Exhibit BMP-4).

Furthermore, the BMPs disputed the company's calculation of the solar LCOE of $70.31/MWh. According to the BMPs, "[t]he calculation of the LCOE value was performed over a 35 year period, which is longer than the 30 year life of the solar project. Correcting the solar LCOE calculation to only account for a 30 year period increases the LCOE to $72.23/MWh." 2 Tr 291 (citing Exhibit BMP-7). Additionally, the BMPs argued that Consumers incorrectly used a 23% solar capacity factor rather than a realistic 20.5% average capacity factor calculated by the BMPs. The BMPs stated that use of the correct 20.5% average capacity factor increases the solar LCOE to $84.36/MWh. *See*, 2 Tr 291-292 (citing Exhibit BMP-7). The BMPs opined that if the company's proposed solar capacity is replaced with BMP capacity, it could reduce the cost of Consumers' amended REP by $3.5 billion. 2 Tr 265. If Consumers' calculations for wind LCOE are correct, the BMPs asserted that the cost of the REP would be reduced by $2.3 billion over the wind project's lifetime by replacing wind capacity with BMP capacity. 2 Tr 290. Moreover, if the solar LCOE were to increase by 40%, the BMPs stated that:

> the solar LCOE would be $126.95/MWh and the wind LCOE would be $77.62/MWH. Adding energy storage at 140% of the $143.54/MWh LCOE, to the solar LCOE, would raise solar LCOE to $154.59/MWh Consumers' ratepayer cost reduction of replacing solar with the BMPS, would be $5.3 billion for solar and $3.2 billion for wind generation over the 30 year life of the generation resource.

2 Tr 290.

In conclusion, the BMPs asserted that Consumers' amended REP should be rejected because the solar LCOE was calculated incorrectly, the company failed to consider the BMPs as a viable renewable energy resource for the REP, the miscalculation of the solar capacity factor results in a shortfall of RECs, the costs of the amended REP were not sufficiently supported, and the Commission will not be able to adequately contain costs. To ensure that biomass generation is included in the amended REP, the BMPs stated that:

> [i]t is important that the RFP evaluation criteria used to determine successful bidders include all the beneficial traits of the BMPS, including the following:
>
> 1. Dispatchable generation that can produce power on a 24/7 basis throughout the year.
> 2. Historic reliability with availability in excess of 90%.
> 3. Does not require energy storage backup like solar, to provide energy during evening hours and winter periods.
> 4. Is not likely to cause negative MISO prices.
> 5. Can provide synchronous generation that supports grid stability.
> 6. Does not degrade over time like solar generation.
> 7. It has a longer operating life than solar energy and battery storage.
> 8. Creates long term Michigan jobs.

2 Tr 299.

Consumers disagreed with the BMPs' claim that the company has assumed a 23% solar capacity factor that is unrealistic. The company asserted that it:

> does not have enough utility-scale solar projects in its portfolio to state that the assumed 23% capacity factor is not realistic. The Company utilized the same solar capacity factor that was utilized in its 2021 Integrated Resource Plan ("IRP"), Case No. U-21090, due to the fact that the Company has not developed/acquired a substantial amount of utility-scale solar that is online and producing enough data to change this value.

2 Tr 349. Consumers stated that it would review any assumptions or changes to the solar capacity factor in its next IRP. The company noted that "the Commission has indicated that 'IRPs remain the most appropriate venue to consider generation diversity as well as renewable resource planning because IRPs allow for the full assessment of renewable resources against other resources . . . .'" Consumers' reply brief, p. 12 (quoting the April 25, 2024 order in Case No. U-21568 (April 25 order) p. 19).

In addition, Consumers disputed the BMPs' conclusion that the company's own generation data shows that the historical capacity factors for Consumers' existing solar projects is between 17.4% and 19.4%, as set forth in Exhibit BMP-5. The company contended that Exhibit BMP-5 contains many errors, including the incorrect capacity for two projects (the remaining projects represent aggregated capacities), and one of the projects did not meet its COD until part way through the year and, therefore, the exhibit does not support the BMPs' argument on this issue. *See*, 2 Tr 349-350.

The company stated that Exhibit A-40 provides data for company-owned or contracted solar facilities 5 MW or larger that were in operation for the entirety of 2024. Consumers noted that these facilities "had capacity factors above the 19.4% that [BMPs' witness] Mr. Polich recommends as the upper bound. In fact, only one of these facilities had a capacity factor that was below 19.4% in 2024 (Willford Solar – 19.34%, 20 MW)." 2 Tr 350-351. However, the company asserted that Exhibit A-40 does not provide enough data to support changes to Consumers' long-term solar capacity factor assumption. More specifically, the company stated that "Exhibit A-40 (ZSC-10) provides solar generation data for a single year. Long-term forecasting should not be based on a single year's generation values since solar production can vary year to year. Additionally, the dataset is relatively small, containing only 530 MW, in comparison to the total amount of solar included in this amended Renewable Energy Plan." 2 Tr 351. Thus, Consumers argued that there is insufficient information in this case to adjust the assumed solar capacity factor as requested by the BMPs.

Next, Consumers disagreed with the BMPs that the company's LCOE of $70.31/MWh is incorrect. The company acknowledges that there was an error in its testimony, claiming that the life cycle for solar projects is 30 years. Consumers asserted that it "intended to file this amended

Renewable Energy Plan assuming a solar useful life of 35 years. The 35-year useful life of solar aligns with assumptions used in recent Company request for proposals ("RFPs") for solar resources." 2 Tr 352.

In addition, the company disputed the BMPs' claim that if Consumers' LCOE of $70.31/MWh is correct, the company could reduce the cost of the REP by over $100 million annually and by more than $3 billion over the lifetime of the solar project by replacing 692 MW of solar with biomass generation. Consumers stated that:

> [t]hese values should not be taken as potential cost savings by including the BMPs in this amended Renewable Energy Plan. These values simply represent the cost of solar needed to produce the aggregated BMPs equivalent amount of renewable energy credits ("RECs"). That is to say that the annual economic benefit was calculated using the BMPs stated amount of annual BMP RECs (1,394,193) multiplied by the corrected solar LCOE of $72.23/MWh. The Life Cycle value on line 11 [of Exhibit A-41] was calculated as the annual value (line 10) multiplied by the BMPs' assumed 30-[year] life of solar energy resources. Additionally, the solar LCOE used in these calculations does not align with the Company's solar LCOE assumption of $70.31/MWh. Regardless of which solar LCOE was used in these calculations, the calculation logic is flawed because these calculations fail to consider any costs associated with the BMPs' contracts. These calculations provide an estimated cost of the 1,394,193 RECs if they were produced by solar facilities but do not provide the equivalent estimated cost of these RECs if they were produced by the BMPs.

2 Tr 353. Consumers asserted that the same flawed logic was applied by the BMPs when claiming that cost savings could be garnered by using the BMPs' calculated LCOE. In conclusion, the company averred that there would be no cost savings by using the BMPs' calculation methodology. *See*, 2 Tr 354-355.

The BMPs disputed Consumers' claim that the company intended to include a 35-year useful life for solar facilities in this case. The BMPs noted that on numerous occasions, the company stated that the useful life is 30 years, including in Consumers' 2021 IRP settlement, in testimony in the immediate case, and in a discovery response in this case. The BMPs asserted that the company has provided no evidence to support the claim that solar facilities have a 35-year useful life and had ample time to update the record in this case. *See*, 2 Tr 311.

Furthermore, regarding the claim that the company's historical solar data should not impact the solar capacity factor, the BMPs asserted that, according to Consumers, "historical data does not matter, and the Commission should simply 'accept' Consumers assumed solar capacity factor of 23% regardless of evidence to the contrary." 2 Tr 311. The BMPs reiterated that Exhibits A-40 and BMP-14 demonstrate that the company's average solar capacity factor for 2021-2024 is below 23%. The BMPs contended that Consumers has not, and cannot, support the proposed 23% solar capacity factor and recommended that the Commission direct the company to include a more reasonable factor in the amended REP.

The BMPs disagreed that the company's solar capacity factor should be reviewed in Consumers' next IRP rather than the immediate amended REP case. The BMPs stated that:

> Consumers ignores the facts that both Act 235 of 2023 and the Commission's Filing Requirements for Renewable Energy Plans post-date the Company's 2021 Integrated Resource Plan proceeding, Case No. U-21090, by more than 2 years. That proceeding was an Integrated Resource Plan ("IRP") proceeding. This proceeding is a Renewable Energy Plan case. It defies logic to conclude that this Renewable Energy Plan should accept the 23% solar capacity factor from its 2021 IRP when (i) neither Act 235's statutory requirements nor the Commission's Filing Requirements for Renewable Energy Plans existed in 2021, (ii) the correct solar capacity factor data are directly relevant to the question of whether Consumers' Amended REP satisfies the requirements of Act 235 and the Commission's Filing Requirements, and (iii) substantial solar capacity factor data is now available that was not available in 2021.

BMPs' reply brief, pp. 1-2.

Finally, the BMPs stated that although they "have the opportunity to bid into [the company's] All Sources Energy Generation Projects RFP," the "2025 All Resources Generation RFP [does not] provide the opportunity for BMPs to bid into renewable energy generation resources." 2 Tr 315. The BMPs explained that in the draft 2025 All Sources RFP, there are three "tranches" of “clean resources” but that the definition of “clean energy” in the 2025 All Sources RFP would exclude biomass generation. 2 Tr 316.

The ALJ found the BMPs’ arguments unpersuasive. He noted that “the Commission has determined that IRPs are the most appropriate venue for considering generation diversity and renewable resource planning, and ‘amended REPs should reflect the assumptions included in the providers’ most recently approved IRP.’” PFD, p. 116 (quoting the April 25 order, p. 19). The ALJ opined that it is reasonable to expect that the first REP amendment after the enactment Act 235 may not align with the utility’s IRP if that IRP was approved before the enactment of Act 235. However, he stated that that is not the case here. Rather, the ALJ found that:

> Consumers incorporates the same 23% solar capacity factor that it used in its most recent IRP (Case No. U-21090), and this PFD finds that factor to be reasonable. Consumers has shown that the data on actual solar performance is too limited to warrant an adjustment to the solar capacity factor at this time. It has also established that the BMPs rely on flawed data to support their argument. Issues involving solar or wind capacity are essential to the modeling that is done in IRP proceedings. Therefore, Consumers’ solar capacity factor should be assessed in its next IRP, with the benefit of additional data.

PFD, p. 116 (citing 2 Tr 349-351).

The ALJ also recommended approval of Consumers’ forecasted solar LCOE. He found that “the BMPs rely on an erroneous capacity factor to support a higher LCOE. In addition, this PFD is not convinced that Consumers’ 35-year solar lifecycle assumption used to calculate the LCOE is unreasonable.” PFD, pp. 116-117 (citing Consumers’ initial brief, p. 59). Furthermore, the ALJ agreed with Consumers that the BMPs’ cost savings calculation that substitutes biomass generation for solar fails to account for the cost of the BMP contracts and is, therefore, flawed and should be rejected.

Finally, the ALJ found the BMPs’ claim unpersuasive that they have been excluded from the RFP process. He stated that although “several of the BMPs are still under contract with

Consumers and were therefore excluded from bidding in the 2025 All Resources Generation RFP, . . . [t]his does not establish that the RFP process is somehow flawed or that those BMPs currently under contract will be unable to participate in future RFPs." PFD, p. 117.

In exceptions, the BMPs reiterate the arguments set forth in testimony and briefing, requesting that the Commission direct Consumers to revise its amended REP to reflect a realistic solar capacity factor, to correct its contradictory position regarding the useful life of solar resources, to calculate the LCOE using the BMPs' data, and to replace some solar and wind generation in the company's REP with biomass generation. *See*, BMPs' exceptions, pp. 7-27.

Consumers replies, stating that "[t]he PFD very thoughtfully and thoroughly addressed the arguments raised by the Biomass Merchant Plants . . . . For the reasons previously stated in the Company's Initial and Reply Briefs, [the BMPs'] arguments are erroneous. The Company asks that the Commission adopt the PFD's findings . . . ." Consumers' replies to exceptions, pp. 15-16.

The Commission finds that the ALJ's recommendation is reasonable and prudent and should be adopted. The Commission agrees with the ALJ that Consumers' IRP is the most appropriate venue to consider generation diversity and renewable energy resource planning. In addition, the Commission notes that the company's proposed 23% solar capacity factor was established in Consumers' most recent IRP and finds that it was appropriately included in this amended REP. The Commission agrees with the ALJ that "Consumers has shown that the data on actual solar performance is too limited to warrant an adjustment to the solar capacity factor at this time" but that it should be reviewed in the company's next IRP when there is additional data. PFD, p. 116. The Commission also finds persuasive Consumers' argument that the BMPs relied on erroneous data to demonstrate that the company's LCOE is incorrect. Moreover, the Commission agrees with Consumers and the ALJ that the BMPs' "cost-savings calculations are flawed because they fail to account for the costs associated with BMP contracts and incorrectly assume BMPs can replace solar capacity on a one-to-one basis." *Id*., p. 113.

Finally, the Commission finds the BMPs' claim that they have been deliberately excluded from Consumers' RFP process to be unpersuasive. The BMPs stated that Consumers' amended REP does not include any biomass generation. In addition, the BMPs noted that "they are not 'clean energy' because they emit CO2 and are, therefore, excluded from all but one of that solicitations' Tranches" and that several BMPs are "under contract with Consumers, which excludes them from bidding." BMPs' initial brief, pp. 23-24. The Commission finds that the circumstances cited by the BMPs are not evidence that Consumers has "gone out of its way to exclude the BMPs from its Amended REP" or that the RFP process is flawed. *Id*., p. 23. As noted by the ALJ, once the BMPs are no longer under contract with Consumers, they "will be [able] to participate in future RFPs." PFD, p. 117.

b. Length of Renewable Energy Plan

The Staff stated that Act 295, as amended by Act 342, established a 20-year renewable energy plan period with a finite conclusion in 2029. However, the Staff asserted that it is unclear whether Act 235 established a finite conclusion for amended REPs. The Staff noted that Consumers "understands that the Amended RE Plan will be for a rolling 20 year period." Exhibit S-1, p. 15. The Staff contended that, for simplicity, it prefers a fixed 20-year period because it establishes a fixed period for levelization of the ICOC, rather than a new levelization for each amended REP. In addition, the Staff stated that the fixed period "would help to encourage a regulatory balance that is as near to zero as possible in the out years (it should be noted that a $200 million regulatory asset or liability is roughly equal to a single 100 MW utility scale solar facility)." 4 Tr 800. Therefore, the Staff requested that the Commission clarify whether the amended REP planning period ends in 20 years or, as Consumers states, is a rolling 20-year period. According to the Staff, this clarification is important because it "is necessary to calculate the levelized ICOC recovery as established in MCL 460.1045(3) for all future AREPs [amended REPs] filed biennially and any potential adjustments in [reconciliations]." 4 Tr 800. The Staff acknowledged that to make a determination as to whether a 20-year finite plan period or a 20-year rolling period is required, the Commission does not have to decide how to manage the ICOC regulatory balance. The Staff contended that "it would recommend modifications in annual [reconciliations] and biennial AREPs to ensure that the regulatory liability remains relatively neutral in the future, as supported within Company witness Johnston's testimony and discovery response." 4 Tr 800.

Consumers stated that it interprets Act 235 as establishing a 20-year rolling period for amended REP filings. According to the company:

> Act 235's amendment of Act 295 removed several references regarding the expiration and conclusion of the 20-year RE Plan period. Instead, under Act 235, Consumers Energy will file an amended RE Plan within two years after an order approving the last amended RE Plan, and each amended RE Plan will include a calculation of the [ICOC] "for a 20-year period beginning with approval of the amended renewable energy plan." Thus, each amended RE Plan filing will include an updated 20-year plan period for calculating the [ICOC].

Consumers' initial brief, p. 61 (citing 2 Tr 797-799; MCL 460.1022(3) and 460.1045). Consumers asserted that in these filings, the company will be able to make adjustments to minimize the liability balance, including possibly reducing the transfer price and implementing a credit surcharge.

The ALJ disagreed with the Staff that clarification is needed in this case. He noted that the:

> Staff acknowledges that it will recommend modifications in annual reconciliations and biennial Amended REPs to ensure that the regulatory liability remains relatively neutral in the future. Moreover, any such clarification will involve application of statutory construction principles to the various versions of the statutory sections which were comprehensively amended, and in this case, no party

> other than Staff provided any testimony on how these amended provisions should be interpreted.

PFD, pp. 119-120. The ALJ recommended that the Commission decline to make a determination in this case until other parties have provided testimony in a subsequent case.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

c. Renewable Energy Plan Statutory Timeline and Contract Approval

GLREA asserted that there are many issues with Consumers' amended REP and, therefore, the Commission should only "look at only 1 or two years of the plan and decide if the first year or two is appropriate and ask for the REP to be reworked for submittal next year or the following year[;] by then some of the important federal budget issues and other department changes should be clarified by then." 4 Tr 613. In GLREA's opinion, the revised amended REP would be more reasonable and would include recommendations provided in the intervenors' testimony.

In addition, GLREA recommended that REP costs associated should be recovered through a rate case. GLREA argued that "[REP] cases should only reflect the plans and determine if the plans are reasonable and prudent but are not a place for cost recovery, especially for very long-term investments like those proposed in this REP, especially during very volatile economic times." 4 Tr 613-614. Furthermore, GLREA contended that if the Commission approves cost recovery in the REP, the Commission will be approving the proposed prices as recoverable when the costs were meant to be estimates, not actual costs.

Consumers objected to GLREA's request that the Commission only review one or two years of the company's REP and direct Consumers to revise the plan. The company stated that it:

> is required, pursuant to statute, to calculate the incremental cost of compliance for a 20-year period. This amended RE Plan carefully and thoughtfully lays out the Company's current plan to achieve the REC standard through 2045. MCL 460.1022(3) requires the Commission to then approve, the amended RE Plan with any changes consented to by the Company or reject the amended RE Plan. Reviewing and approving only one or two years of the Company's amended RE Plan is not a viable option.

2 Tr 119. In addition, Consumers noted that because it is required to file another amended REP in two years to demonstrate compliance with the RPS, this requirement may assuage GLREA's concerns.

In response to GLREA's claim that REP cost recovery should be in a rate case, the company asserted that, as in the past, "the costs for complying with the REC standard have been and will continue to be presented in renewable energy plans and have been and will continue to be reconciled annually in renewable cost reconciliation cases. While Act 235 has added an option for recovery of the incremental cost of compliance in base electric rates, the Company has chosen not to pursue this option." 2 Tr 119-120.

Moreover, Consumers averred that Commission approval of the amended REP is not definite approval for REP cost recovery. Rather, the company stated that Commission approval in this case:

> is approving the Company's plans for the addition of renewable energy resources and the projected costs associated with the Company's plan. Projects that are developed and whose levelized costs are below the LCOE thresholds will still require Commission approval, but that approval can be provided on an ex parte basis. Projects whose levelized costs are not below the LCOE thresholds are required to be filed for approval but will require a contested case proceeding prior to Commission approval.

2 Tr 120. Consumers reiterated that after the costs are incurred, the company will file an annual renewable cost reconciliation in a contested case wherein Consumers must present actual costs for review and approval.

The ALJ found GLREA's requests to be contrary to Act 235 and unsupported. He also "agree[d] with Consumers that GLREA's assertions regarding cost recovery are misguided and are in direct conflict with REP cost recovery processes." PFD, p. 122. Therefore, he recommended that GLREA's concerns and suggestions be rejected.

No exceptions were filed on this issue.

The Commission finds the ALJ's recommendation to be reasonable and prudent and that it should be adopted.

THEREFORE, IT IS ORDERED that:

A. Consumers Energy Company's renewable energy plan is approved, in part, as described in this order.

B. Consumers Energy Company's proposed incentive renewable energy credits, as calculated using the "peak demand hours" set forth in the December 4, 2008 temporary order in Case No. U-15800, are approved for 2023. However, until the Commission determines whether any adjustments should be made to how incentive renewable energy credits are calculated, the Commission declines to approve the company's incentive renewable energy credits for 2024-2045.

C. Consumers Energy Company shall accelerate its acquisition of new wind resources, as set forth in this order, which may include actively soliciting power purchase agreements for wind generation outside of Midcontinent Independent System Operator, Inc., Zone 7.

D. For Consumers Energy Company's 140% levelized cost of energy multiplier, in future plans, the upper cost limit in the company's renewable energy plan shall be tied to the upper cost limit included in the company's most recently approved integrated resource plan and vice versa.

E. In Consumers Energy Company's next integrated resource plan, the company shall evaluate various load growth scenarios, including storage and curtailment.

F. Consumers Energy Company shall implement a competitive bidding process for wind and energy storage resources, shall actively solicit third-party power purchase agreements in all its future requests for proposals, and shall use an independent administrator in its competitive bidding process, as described in this order.

G. Consumers Energy Company shall include the withdrawal of cost recovery for co-located energy storage projects in subsequent biannual amended REP filings and its 2025 REP reconciliation.

H. Within 14 days of this order, Consumers Energy Company shall file a statement in this docket that it consents to the changes to its renewable energy plan as contained in this order, pursuant to MCL 460.1022(3). Failure to submit such statement within the 14-day time period shall void the Commission's approval of the company's renewable energy plan. If Consumers Energy Company does not consent to the changes to its renewable energy plan as set out in this order, the company shall file a revised renewable energy plan in this docket no later than January 12, 2026.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at LARA-MPSC-Edockets@michigan.gov and to the Michigan Department of Attorney General - Public Service Division at sheac1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Katherine L. Peretick, Commissioner

Shaquila Myers, Commissioner

By its action of September 11, 2025.

Lisa Felice, Executive Secretary

P R O O F   O F   S E R V I C E

STATE OF MICHIGAN)

Case No. U-21816

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on September 11, 2025 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna J. Brown

Brianna Brown

Subscribed and sworn to before me
this 11th day of September 2025.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2030

Service List for Case: U-21816

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