MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

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MPSC 2025 Symposium

Transfer Price Methodology, On-Peak, & Storage Incentive RECs

In accordance with the Commission Order in Case No. U-21662

September 1, 2025

Staff of the Michigan Public Service Commission

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LICENSING AND REGULATORY AFFAIRS

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AWAITING FINAL REVISIONS

Introduction

On May 15, 2025, the Michigan Public Service Commission (MPSC or Commission) issued an order approving the settlement agreement submitted in Case No. U-21662 (May 15th Order). This case, which involved a review of DTE Electric Company's (DTE) amended renewable energy plan (REP), instructed MPSC Staff (Staff) to convene a symposium to evaluate the calculation of transfer prices. The Commission Order and settlement agreement also instructed Staff to convene a work group to revise the definition of on-peak hours for the determination of incentive renewable energy credits (RECs). While not expressly outlined in the Order, the Symposium and therefore this report also addresses incentive RECs for storage assets. These directives were combined by Staff and covered during a single symposium. Much of the discussion around these topics between Staff, DTE Electric Company, and various intervening parties was prompted by broad changes to Michigan's renewable energy regulation landscape that were put in place by Public Act 235 of 2023 (PA 235).

Originating in Public Act 295 of 2008 (PA 295), the transfer price is a method which allows electric providers to account for and recover the cost of energy sourced from renewable generation. PA 295 specifically calls for electric providers to determine an incremental cost of compliance (ICC) incurred in complying with the State of Michigan's renewable energy standards. Under the currently utilized methodology, the ICC is defined as any additional cost above the dollar per megawatt-hour ($/MWh) transfer price that is assigned to a given renewable generation project. Electric providers began filing individual and unique transfer price schedules with their REPs that were submitted in 2009. Starting in 2012, Staff began issuing an annual transfer price schedule (Staff Transfer Price) update to be used in this calculation that is designed to approximate the cost of energy from a generic, non-renewable electric generation source.

Incentive RECs are additional renewable energy credits granted to electric providers if certain conditions are met. This also originated in PA 295 but has since been modified by PA 235, Section 39. The conditions under PA 235 to earn incentive RECs relate to the source of energy provided, the time at which the energy is provided, and/or the means by which a given renewable energy project was constructed. In addition, PA 235, Section 39, outlines conditions in which incentive RECs can be created through the charging of a storage facility during off-peak hours using renewable resources that is then discharged on-peak. The discussion in this report, in accordance with the Commission's May 15th Order, will focus primarily on the definition of on-peak demand hours that is used to award incentive RECs and how these incentive RECs are calculated for storage facilities.

Staff hosted an online symposium on June 5, 2025 (June 5th Symposium), to address the Commission's Order to reevaluate the Staff Transfer Price methodology, on-peak definition, and incentive RECs from storage. Presentations were by MPSC Staff Member Jesse Harlow, Manager of the Renewable Energy Section and by 5 Lakes Energy Representative Douglas Jester. Douglas Jester has also represented

Michigan Environmental Council – Sierra Club (MEC-SC), both witnesses in Case No U-21662. Various interested parties attended the symposium to view the presentations and participate in collaborative discussions on these topics. Since the Symposium, public comments have been entered into the record by various intervenors.

Transfer Prices

Origin of Transfer Prices

PA 295, a first-of-its-kind renewable energy regulation for the State of Michigan, enacted a number of new standards for how clean energy, renewable energy, and energy optimization would be regulated in the State. The most consequential of these requirements was that electric providers must source 10% of their electric generation from renewable sources by 2015. This original renewable portfolio standard (RPS) spurred a substantial investment in renewable energy generation by electric providers. In order to quantify the spending necessary to comply with the RPS and other regulations included in PA 295, the law also directed electric providers include the expected ICC in renewable energy plan filings. PA 295 defined the ICC as, "*the net revenue required by an electric provider to comply with the renewable energy standard.*" The transfer price was then devised as the method by which the ICC could be determined. Transfer prices serve as a stand-in for the cost of non-renewable generation that would have otherwise been acquired by the electric provider. The ICC can be defined as any cost above a renewable energy project's associated transfer price.

The transfer price concept was originally established with a Commission Order in Case No. U-15800 on December 4, 2008. This order stipulated that the ICC be calculated via the transfer price and that the transfer price be recovered through the power supply cost recovery (PSCR) mechanism. Transfer price schedules would be estimated over a 20-year period and were to be established in the context of an annual renewable energy cost reconciliation proceeding. Under this framework, electric providers carrying an ICC balance calculated transfer price schedules independently, filed those schedules in annual renewable reconciliation cases, and the appropriate transfer price from each schedule was applied to all projects approved by the Commission for that utility in the following year. Once a transfer price is assigned to a renewable project, that transfer price is established as a ceiling for the lifecycle of a power purchase agreement (PPA) or company-owned facility. Transfer price schedules were implemented in this manner from 2009 through 2011.

Following a Commission Order in Case No. U-16582 on December 20, 2011, Staff was directed to convene the first symposium (2012 Symposium) with electric providers and other intervening parties to consider revising the transfer price methodology. During this symposium and the following discourse, a consensus was reached that the transfer price should be based around a non-renewable electricity generation technology that would likely come to represent a broad industry standard: the natural gas combined cycle (NGCC) generation plant. At the direction of the Commission, Staff and intervenors devised a new transfer price methodology that would allow for greater transparency in calculating transfer price schedules while also protecting the confidential information held by involved parties. Staff began publishing a Staff Transfer Price Schedule under this new methodology in 2012 that could be used by electric providers as a basis for individual company transfer price

schedules. The transfer price schedules published by Staff in the U-15800 Docket and in individual electric provider's annual renewable energy reconciliation filings have been consistently approved by the Commission since the first Staff Transfer Price schedule was established in 2012.

Current Methodology

Since the current Staff Transfer Price methodology was developed after the 2012 Symposium, annual Staff Transfer Price schedules have been designed to approximate the $/MWh cost of energy from a generic, non-renewable electric generation source (Generic Plant). The Generic Plant cost approximated in this calculation continues to be the cost of an NGCC plant, levelized over a 20-year period, with the electricity produced being purchased under a long-term PPA at market price.

Transfer prices calculated under the Staff methodology are comprised of two cost components: a fixed component and a variable one. Fixed costs are derived from characteristics of the NGCC technology or generation inputs which are not generally affected by short-term market conditions. The overall methodology has remained the same since 2012 but the data is updated annually. The most recent Staff Transfer Price schedule includes the following:

Fixed Cost	**Value**	**Notes**
Capacity	400	MW
Loading Factor	71.00%	Percentage of time the unit is dispatched if available.
Equivalent Availability	87.00%	Percentage of time the unit is available for dispatch.
Fixed Operations & Maintenance	$14.62	$/kWh
Fixed Charge Rate	11.59%	Percentage used to calculate fixed cost recovery component.
Annual Levelized Fixed Cost	$75.36	Million dollars
Total Annual Levelized Fixed Cost	$81.21	Million dollars

Variable costs are derived from characteristics of the fuel used for electricity generation and inputs which are more affected by short-term market conditions. The main driver of variable costs is the cost of natural gas fuel. Variable cost inputs include the following:

Variable Cost	Value	Notes
Heat Rate	6,719	BTU/kWh
Fuel Cost - BTU	$4.33	$ / million BTU
Fuel Cost – kWh	$0.0291	$/kWh
Variable Operations & Maintenance	$0.0031	$/kWh
Total Variable Cost	$0.0322	$/kWh

In order to approximate an appropriate cost of energy, Staff incorporates a levelized cost calculation that includes an Allowance for Funds Used During Construction (AFUDC) to account for the cost of construction and NYMEX Henry Hub Natural Gas pricing data to estimate future fuel costs. AFUDC is calculated over a four-year period using a total overnight cost in 2021 dollars of approximately $540 million, a standard inflation rate of 2%, and a finance rate of 6.56% based on previous utility financing data.

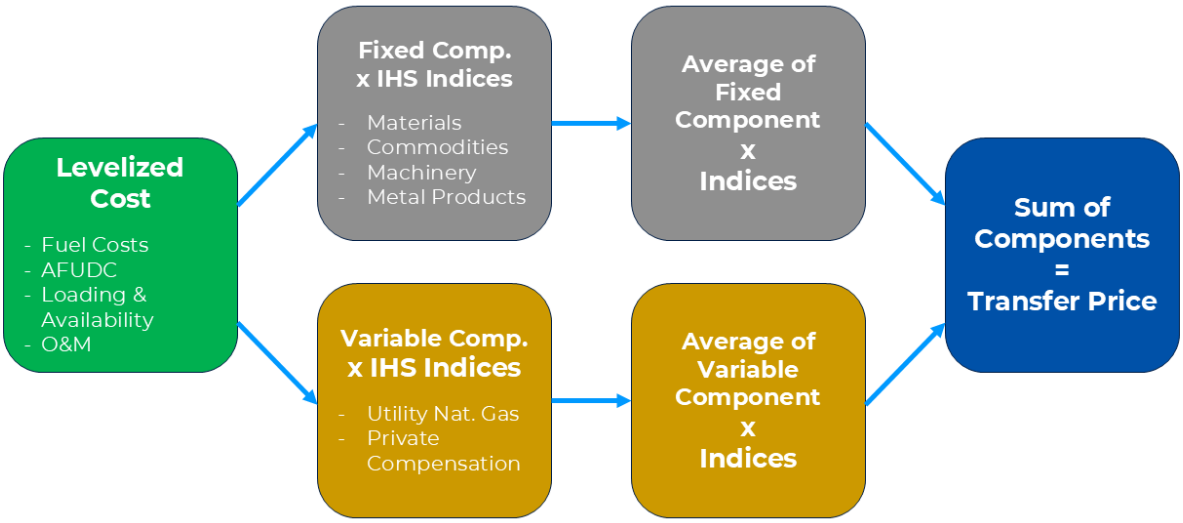
Data from IHS Global Insights indices (IHS Indices) are used to estimate the cost of relevant inputs to the generation process and to project those costs over the full plan period ending in 2045. The data sourced from IHS and used in the forward projection that produces the full transfer price schedule is the only piece of confidential information used in the Staff Transfer Price methodology. IHS Indices data is purchased from IHS Global Insights by Staff, utilized in calculating transfer price schedules, and later redacted[1] when the annual transfer priced update report is published to the U-15800 Docket and entered as testimony in individual electric provider renewable energy reconciliation cases. The IHS Indices utilized in the Staff methodology are divided between the fixed and variable components and include the following:

IHS Index	Component
Producer Price Index – Intermediate Materials	Fixed
Producer Price Index – Industrial Commodities	Fixed
Producer Price Index – Machinery & Equipment	Fixed
Producer Price Index – Metals & Metal Products	Fixed
Producer Price Index – Utility Natural Gas	Variable
Producer Price Index – Total Private Compensation	Variable

[1] While this IHS Index data is redacted in the annual Staff Transfer Price update report, Staff will make it available to view in office upon request to preserve transparency.

After projecting the fixed and variable components for each remaining year of the plan period, an average of the index data is taken for the fixed and variable components. The sum of fixed and variable component averages for each year of the plan period is the transfer price in that year of a given transfer price schedule. The following graphic shows a high-level overview of how transfer price schedules are calculated, while Staff's full 2025 transfer price schedule update report is included as Exhibit 1.

Figure 1: Staff Transfer Price Calculation Process



Proposed Changes to Methodology

Current discussion around proposed changes to the Staff Transfer Price methodology originated in MPSC Case No. U-21662 where DTE pursued an application for an amended REP, as required by statue. Testimony and exhibits entered into the record by Douglas Jester, a witness for MEC-SC, asserted a need to modify the calculation of transfer prices in response to the Clean Energy Portfolio (CEP) standards adopted in PA 235. These CEP standards require that electric providers achieve a clean energy portfolio of 80% from 2035 through 2039 and 100% in each year thereafter. An NGCC plant, which is currently the generic, non-renewable generator approximated in the Staff methodology, is not considered a clean source of electric generation under the definition provided in the law. To qualify as clean energy as set forth in PA 235, the energy must be sourced from a clean energy system. The definition of a clean energy system is as follows:

(i) "Clean energy system" means an electricity generation facility or system or set of electricity generation systems that meets any of the following requirements:

(i) Generates electricity or steam without emitting greenhouse gas, including nuclear generation.

(ii) Is fueled by natural gas and uses carbon capture and storage 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 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. Using carbon dioxide for enhanced oil recovery is not considered to be permanent storage for the purposes of this subparagraph.

(iii) Is an independently owned combined cycle power plant fueled by natural gas that has a power purchase agreement with an electric provider as of the effective date of the amendatory act that added this subparagraph and that by 2030 receives approval from the commission for a plan that achieves functional equivalence with the clean energy standard in section 51(1)(b) through reduction of greenhouse gas emissions using carbon capture and sequestration and other available applications, including, but not limited to, carbon removal technologies. In reviewing and approving a plan submitted under this subparagraph, the commission shall consider best available technology and applications as well as rate affordability, resource adequacy, and grid reliability.

(iv) Is defined as a clean energy system in rules adopted by the commission consistent with the purposes of this subdivision.

The testimony filed by Witness Jester claimed to resolve the apparent conflict between Staff's current transfer price methodology and the CEP requirements included in statute. Witness Jester asserts that an NGCC plant can only serve as the Generic Plant in Staff's methodology if an additional cost of carbon capture and storage is included in the calculation of the Staff Transfer Price Schedule. This necessity would arise from Section 3 of PA 235 which states that an electric generation system fueled by natural gas may be considered "clean" if and only if it utilizes, "*carbon capture and storage that is at least 90% effective in capturing and permanently storing carbon dioxide.*" Given this potential conflict between the industry standard for electric generation and the CEP standards, Witness Jester states that, "*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.*"

To address the claimed misalignment between the Staff Transfer Price methodology and a possible, future industry standard practice for electric generation, Witness

Jester recommends that the Commission adopt an incremental cost added to the transfer price. This incremental cost would be based on the U.S. Environmental Protection Agency's (EPA's) estimated cost of compliance with carbon capture and storage (CCS) regulations. The EPA analysis produced an incremental cost of $19/MWh in 2019. Witness Jester's individual analysis concludes that an appropriately adjusted incremental cost to stand for approval by the Commission would be estimated at $22.66/MWh.

Given that the transfer price is a portion of the calculation necessary in determining the ICC for REPs, it is important to consider the effect that this proposed change would have on the ICC. Witness Jester asserts that by adding incremental cost of carbon capture in transfer prices, a situation may present itself where it is no longer necessary for electric providers to carry a regulatory liability balance. In the case of DTE, Witness Jester proposes that the Commission direct DTE to disburse any remaining regulatory liability balance to ratepayers as a sur-credit in some future year. At the time of Witness Jester's testimony filing in Case No. U-21662, DTE presented an estimated regulatory liability balance of $21 million at the beginning of the REP that was projected to steadily increase through the 20-year REP period.

The presentations given by Staff Member Jesse Harlow, Manager of the Renewable Energy Section, and Witness Jester at the June 5th Symposium on the topic of transfer prices are also included in this report as Exhibit 2 and Exhibit 3.

Summary of Intervenor Comments

Following the June 5th Symposium, any interested parties were invited to provide formal comments on the record in the U-15800 Docket regarding the covered topics. The following sections will summarize the comments relating to transfer prices that were filed by Association of Businesses Advocating Tariff Equity (ABATE), Consumers Energy Company (Consumers), DTE, and the Michigan Environmental Council (MEC). The full text of these comments are included as exhibits in this report. It should be noted that at the time of the Symposium, Consumers had an active Renewable Energy Plan case before the Commission that contained similar opinions and suggestions from intervening parties.

ABATE – Transfer Price

The full comments entered into the record by ABATE are presented in this report as Exhibit 5. ABATE begins its discussion of transfer prices by first providing an overview of the history of the topic and the current methodology. The details of this overview are consistent with those presented by Staff earlier in this report. ABATE also responds to several options that were discussed during the June 5th Symposium. These options include eliminating the transfer price mechanism and instead recovering the relevant costs in base rates, maintaining the current Staff Transfer Price methodology, adding the cost of CCS to the transfer price as proposed by MEC-SC, and modeling a renewable generation resource like solar.

The basis for ABATE's consideration of eliminating the transfer price mechanism altogether is that the initial intent in PA 295 was to account for excess costs incurred

in pursuing renewable development to comply with RPS requirements. If utilities are pursuing renewable generation resources for both RPS compliance and general supply needs, then the cost of renewables could be a better basis for the transfer price in this context. If the transfer price is equivalent to the cost of renewable generation, then excess cost to be recovered as the ICC is zero, thus eliminating the need for a transfer price mechanism. As the cost of renewable generation has decreased in recent years, the ICC has decreased or even become negative. A negative ICC would lead to an increase in an electric provider's regulatory liability balance. ABATE asserts that Staff believes the Commission has great latitude to set the transfer price and that the transfer price should be set at whatever level is necessary to support renewable energy plans. Such an approach, in ABATE's opinion, would be prudent and would allow the Commission to reduce electric providers' regulatory liability balances while avoiding over-recoveries.

ABATE does find the current Staff Transfer Price methodology to be a sufficient approach to continue utilizing at this time. The current methodology ensures that the actual cost of renewable generation resources is recovered, and a reasonable regulatory liability balance is recovered without the need for a REP surcharge or bill credit (sur-credit). Capacity and energy costs are appropriately classified when PSCR costs are reflected in base rates.

In ABATE's opinion, it is premature to integrate the cost of CCS into the transfer price. ABATE asserts that statute does not stipulate that the transfer price be based on a non-renewable resource and that CCS technology would not be required for NGCC resources to be classified as "clean" until 2040. The use of CCS alongside NGCC generation plants is not currently widespread in Michigan or the United States more broadly. Not only are Michigan electric providers not currently pursuing CCS technology in order to classify NGCC plants as clean energy systems, the CEP standard requirements could be met by utilizing clean energy systems which are entirely unrelated to natural gas and fossil fuel fired generation. In this case, there would be little basis for adding an incremental CCS cost to the transfer price.

ABATE cites that Staff has testified in Case No. U-21816 that solar resources have been overwhelmingly selected as the preferred generation resource in recent integrated resource planning (IRP) cases. Staff also noted in this case that a transfer price based on solar generation would likely be lower than transfer prices based on NGCC generation under the current methodology. ABATE also notes that intervenors such as MEC have not opposed basing the transfer price on, for example, the actual cost of Consumers' solar resources. ABATE finds this approach to be appropriate for further consideration.

Consumers' and DTE's REPs are cited to show that Michigan's two largest electric providers are already projecting regulatory liability balances between $300 million and $1.5 billion under the current Staff Transfer Price methodology. ABATE expresses concern that increasing the transfer price would lead to even greater over-recoveries and would significantly increase regulatory liabilities, necessitating some sort of scheme for crediting funds back to ratepayers. The need to begin crediting large regulatory liabilities back to ratepayers would also raise the issue of how to allocate

costs between different customer classes. Allocating costs and crediting an unnecessarily large regulatory liability to ratepayers would further deviate from the electric provider's requirement to accurately recover the actual cost of service.

In summary, ABATE asserts that a reasonable cost recovery approach should achieve the following: ensure electric providers recover the actual cost incurred to comply with RPS requirements, appropriately classify and allocate production costs on the basis of demand and energy, and avoid further increasing over-recoveries from ratepayers. ABATE does not believe that the inclusion of CCS costs in transfer prices achieves these objectives and thus is not a reasonable strategy for modifying the transfer price methodology. ABATE's position is that transfer prices should collect the actual cost of compliance with RPS requirements and result in the elimination of regulatory liabilities at the end of the compliance period.

Consumers – Transfer Price

The full comments entered into the record by Consumers are presented in this report as Exhibit 6. Consumers' position on the subject of the Staff Transfer Price methodology is that it is not necessary to make any modifications to include a projected cost of carbon capture. The company presents several points to support this position.

The current methodology does provide sufficient revenue recovery over the 20-year plan period to fund the REP filed by Consumers in Case No. U-21816. The company states that, while it will hold a regulatory liability balance at the end of the plan period, it has an objective to charge ratepayers only the cost to provide service. Further increases to the transfer price would be counter to that objective. Consumers' comments state specifically that, "*the Company does not believe that it should collect revenue from customers today in order to refund it to future customers.*" Additionally, Consumers believes that it is premature to modify the Staff Transfer Price methodology when CCS technology does not currently have a high adoption rate and is not required to classify an NGCC plant as a clean energy system under the CEP standards for another ten years. The company expects to file at least three subsequent REP applications over that ten-year period, leaving ample opportunity to reevaluate the Staff Transfer Price methodology at a later date. There are already a number of methods by which Consumers can recover the revenue needed to fund its REP, including via base rates or a surcharge, that do not necessitate an increased cent/kWh PSCR factor which may result in harm to certain customer classes.

Consumers has also not yet determined how it will meet CEP standards. An NGCC plant with CCS, renewable generation, nuclear generation, and even natural gas-fueled peaking plants may be potential options for reliably serving customers during the transition to clean energy. Consumers will continue to evaluate options for alternative capacity and energy resources and present further plans in its upcoming 2026 IRP.

DTE – Transfer Price

The full comments entered into the record by DTE are presented in this report as Exhibit 7. DTE states that there is potential merit in MEC's proposed changes to the Staff Transfer Price methodology. Despite this, the company believes that any changes to the transfer price methodology should be delayed until after Michigan's investor-owned utilities (IOUs) conclude the next series of IRP filings. The company asserts that the IOUs are likely to receive information regarding the viability of CCS in electric generation and that delaying changes to the transfer price methodology will not affect customers rates. DTE is currently forecasting a near-term regulatory liability.

MEC – Transfer Price

The full comments entered into the record by MEC are presented in this report as Exhibit 8. MEC's comments on the issue of the transfer price methodology begin with a brief statement of the purpose of the transfer price which is to allow electric providers to determine the ICC and recover any additional costs incurred in complying with renewable energy standards. Further discussion covers the series of events which led to the methodology that is currently utilized by Staff. A key point of this discussion is that the current methodology was established by the Commission based on an agreement with Staff about what technology should be the basis for estimates of the cost of conventional electric generation. Staff and the Commission agreed that the electric generation industry would likely trend towards the construction of NGCC plants and that that is the technology which should be utilized as the basis for the transfer price. The basic framework for calculating the Staff Transfer Price Schedule has remained unchanged since 2012.

MEC asserts that the current Staff transfer price methodology must be updated in response to the passage of PA 235 which will require electric providers to meet new CEP standards. These standards may necessitate the use of CCS technology alongside NGCC plants such as the one modeled in the Staff methodology. Any NGCC plant operating in Michigan beyond 2034 would require the use of a 90% effective CCS system to be classified as a clean energy system and thus contribute to an electric provider's CEP. That efficacy requirement would rise to 100% in the year 2040. Additionally, a new rule issued by the EPA in 2024 requires that any new gas plants make use of a 90% effective CCS system by 2032. This EPA rule remains subject to legal challenge.

MEC states that, if the transfer price continues to be based on the cost of conventional new generation, then the methodology should account for the cost of CCS. If an electric provider instead opts to utilize only new renewable resources, then the transfer price should be based on the cost of those renewable resources. MEC supports either of these proposed changes to the Staff Transfer Price methodology.

On-Peak Definition & Incentive RECs from Storage

On-Peak Definition History

The concept of incentive RECs was first introduced with the passage of PA 295 in 2008. Under the framework established in PA 295, additional RECs were granted to electric providers in certain circumstances. While the conditions that could be met to earn incentive RECs range from utilizing certain types of generation to building projects using an in-state workforce, this report will focus primarily on incentive RECs that are awarded for providing renewable energy during hours of peak demand and the Commission's definition of on-peak hours.

Following the passage of PA 295, the Commission established the U-15800 Docket to handle the implementation of certain parts of the then-recently enacted law. The definition of on-peak hours utilized today in awarding incentive RECs was first approved by the Commission in a temporary order on December 4, 2008. During the MPSC Case No. U-21662, which involved DTE's application for an amended REP, there was some debate over the continued validity of the current on-peak definition. The argument was made by some intervening parties that, due to the changing landscape of electricity generation and shifts customer electricity usage habits, the actual hours of peak demand have shifted substantially from the Commission's on-peak definition. If the purpose of incentive RECs is to incentivize a certain type of generation within a certain timeframe, then this misalignment may present a need for corrective action and thus a revision of the on-peak definition. While this may be the case, the Commission's current on-peak definition remains mostly in alignment with that of the Midcontinent Independent System Operator (MISO). The U-15800 Docket currently defines on-peak as the hours between 0600-2200 (EST) while the most up to date MISO definition is 0700-2200 (EST).

Two subsequent renewable energy laws have been enacted by the State of Michigan since the passage of PA 295 in 2008. These laws include Public Act 342 of 2017 and Public Act 235 of 2023. These laws have not modified the general structure of the incentive REC system or explicitly called for a reevaluation of its implementation, including the on-peak definition utilized by the Commission.

On-Peak Incentive RECs from Storage

Electric storage technologies are another mechanism through which electric providers can earn incentive RECs by supplying power from renewable generation sources during on-peak hours. Section 39.2(c) allows electric providers to earn incentive RECs for supplying energy that is generated by a renewable energy system during off-peak hours, put into storage, and used during peak hours. The current implementation of this incentive REC mechanism assumes that a renewable generation source is being utilized to charge a storage facility if it is generating power while that storage facility is being charged. Intervenor testimony in Case No. U-21662 argued that this assumption is unreasonable and that incentive RECs

should only be awarded for energy from storage at a rate which is proportional to the share of renewables that were generating while the facility was charging.

Current On-Peak Definitions

Staff On-Peak Definition

As previously stated, the Commission's current definition of peak demand time was established in a temporary order issued in the U-15800 Docket. Under this definition peak demand time is defined as:

> "*the period of time between 0600 hours Eastern Standard Time (EST) through 2200 hours EST, Monday through Friday excepting New Year's, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day or if the holiday occurs on a Sunday, the Monday immediately following the holiday.*"

At the time of the temporary order, this definition was selected to align with the definition utilized by MISO for peak demand time. While the definition utilized by MISO has changed slightly since the Commission adopted the definition that is currently utilized by Staff, the two only differ by one hour at this time.

It should also be noted that MISO's definition of on-peak hours is context dependent. The definition used when discussing energy is 0700-2200 EST. The definition used when discussing capacity demand and accreditation is undergoing changes set to be implemented in 2028 using a variable 60 hours per year based on loss of load analysis. RECs are measured on the basis of energy provided. A single REC is defined by statute as being equivalent to one megawatt-hour of electricity generated by a renewable energy system.

MISO On-Peak Definition

Despite shifting the start time of peak demand hours slightly from 0600 in 2008 to 0700 today, the definitions utilized by MISO and by the Commission remain nearly identical. The full definition of peak demand hours utilized by MISO is as follows:

> "*Period of time between Hour-ending 0700 EST through and including Hour-ending 2200 Hours EST Monday through Friday excepting New Year's, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day or if the holiday occurs on a Sunday, the Monday immediately following the holiday.*"

A great deal of discussion around the issue of revising the on-peak definition utilized by the Commission centers around MISO's plans for the future with regard to this issue. Changes have been proposed by MISO and accepted by the Federal Energy Regulatory Commission that will change how load-serving entities are accredited under a new Direct Loss of Load base methodology. Additional changes may take into account load modifying resources and an observed delta between peak demand hours and the times at which the risk of a loss of load is highest. While MISO is in planning revisions to the process through which load serving entities are accredited in order to better address loss of load risks, Staff is not aware of any MISO

plans to revise the general definition of on-peak hours set at 0700-2200 EST at this time.

Proposed Changes to On-Peak Definition

During DTE's most recent REP case, MEC-SC Witness Douglas Jester argued that the current on-peak definition utilized by the Commission to award incentive RECs is no longer valid and should be revised. Witness Jester proposes that the Commission base its definition of peak demand time on the times when non-wind renewable resources provide capacity value as accredited by MISO. Witness Jester argues that the current system by which incentive RECs are assigned for on-peak renewable generation no longer aligns with when renewable generators provide incremental value in a way that reduces the need for other resources. Additionally, Witness Jester proposes that the Commission continue to adapt its on-peak definition and incentive REC methodology on an ongoing basis in response to any future changes in the MISO capacity accreditation methodology.

Proposed Changes to Incentive RECs from Storage

In addition to revisions to the on-peak definition, MEC-SC also proposed changes to the incentive REC mechanism during the DTE case in MPSC Docket U-21662. Witness Jester's proposed changes to the storage incentive REC mechanism are centered around the assumption that it is unreasonable to assume that a renewable generator operating while a storage facility is being charged is necessarily responsible for providing the energy that is stored. Storage facilities in Michigan, such as the Ludington Pumped Storage Plant (Ludington) discussed in the DTE case, may regularly draw energy for charging from the MISO grid. This incremental load will be served by the MISO grid from a dispatch queue that is based on cost. Although renewable generators may be operating and supplying power to the grid at the time of charging, this power is not necessarily selected to serve the charging load unless it is the cheapest option available. Essentially, he claims, Ludington is charged utilizing resources that are dispatched at the end of the merit order since traditional customer load would be the first to be served. Since renewable generation would most likely be the first to be dispatched, he argues that storage would most likely be charged using any remaining generation in the merit order, namely non-renewable generation.

To address the potential overrepresentation of renewable generators in the charging of storage facilities, Witness Jester recommends assigning RECs to provide renewable generation at a rate that is equal to the proportion of renewable generators providing power to the grid at the time of charging. Such an approach would likely greatly reduce the number of incentive RECs awarded for supplying renewable energy for storage charging purposes because RECs would no longer be awarded to renewable generators who are available on the market at the time of charging but are not necessarily the most economic option.

The presentations given by Staff Member Jesse Harlow, Manager of the Renewable Energy Section, and Witness Jester at the June 5th Symposium on the topics of on-

peak hours and incentive RECs are also included in this report as Exhibit 2 and Exhibit 4.

Summary of Intervenor Comments

Consumers – On-Peak Definition & Incentive RECs from Storage

The full comments entered into the record by Consumers are presented in this report as Exhibit 6. The company's stated position is that the definition of on-peak hours does not need to be updated. Consumers' first argument, which relates to the statute defined in MCL 460.1039(2)(b), is that projected capacity deficits are a result of how generation assets receive accreditation and are not a result of the peak demand time definition. The company argues that projections showing a potential scarcity of capacity in relation to demand during certain hours of the day is not a valid reason to revise the on-peak definition.

The company's second argument against revising the on-peak definition and incentive REC mechanism would have a significant impact on Consumers' ability to comply with PA 235. The company's models have been based on the existing system for a significant period of time and the reduction or elimination of millions of incentive RECs could necessitate the development of nearly 2,000 MW of new renewable generation. Such a dramatic increase in the company's need for new renewable generation would place a greater strain on customer affordability.

Lastly, Consumers intends to install significant energy storage capacity in order to capture renewable energy during both peak and non-peak hours in order to meet capacity requirements during projected future tight capacity periods. The company argues that there is already sufficient incentive to have sufficient renewable generation to charge that planned storage capacity.

DTE – On-Peak Definition & Incentive RECs from Storage

The full comments entered into the record by DTE are presented in this report as Exhibit 7. DTE characterizes the suggested changes to the on-peak definition presented during the June 5th Symposium as a request to move from the current MISO peak demand time definition to the MISO definition used to accredit solar resources. The company states that this would result in a substantial decrease in the hours used to calculate incentive RECs; for example, reducing the number of summer weekday hours from sixteen to three.

DTE asserts that this proposal is flawed for two reasons. First, the definition of on-peak hours would no longer be based on "peak demand time" as is required by statute in MCL460.1039(2)(b). MEC's suggested new definition would instead be based on peak capacity risk. Second, MEC's proposed new definition would suggest that the value storage provides in shifting renewable energy from off-peak to on-peak hours is exclusively related to capacity. This would ignore other benefits such as energy arbitrage, congestion relief, and other ancillary services. DTE's stated position is that, in order to comply with the mandate set by the State legislature, the

Commission should continue to use the MISO definition for all utilities within the State.

The company also opposes modifying the incentive REC mechanism in the way that MEC has proposed. DTE interprets MEC's understanding of the current system to be that renewable generation is not likely to be used for charging storage facilities because it is dispatched early in the merit order. The company disagrees with this assertion because it is incorrect to assume that any individual or incremental load on the MISO system is served by the marginal resource. A marginal resource represents the last unit dispatched to meet system-wide demand, not the specific energy source in serving any particular load. MISO determines the marginal resource using a system-wide model and calculates the market clearing price but cannot track the specific flow of electricity directly from one generation source to a given load or storage facility. DTE's position on the matter is that it is acceptable to assume that a company's renewable generation is being utilized in charging a storage facility even if another resource elsewhere in MISO is offering a higher price.

MEC – On-Peak Definition & Incentive RECs from Storage

The full comments entered into the record by MEC are presented in this report as Exhibit 8. MEC begins its comments on this topic by discussing the background of the Commission's current on-peak definition. The Commission's current definition defines peak demand time as the hours of 0600 through 2200 EST and was first implemented by a temporary order issued to the U-15800 docket in 2008. Since the passage of the original temporary order, minor changes have been made by the Commission to account for new requirements that were enacted by PA 235. Despite this, no changes have yet been made to the Commission's implementation of the current statute's incentive REC mechanism. MEC comments cite an agreement from the administrative law judge in Case No. U-21662 stating that, "*the definition could stand to be revised.*"

Exhibits

Exhibit 1 : 2025 Staff Transfer Price Schedule Update Report

Exhibit 2 : MPSC Staff Presentation - 2025 Symposium

Exhibit 3 : 5 Lakes Energy Transfer Price Presentation - 2025 Symposium

Exhibit 4 : 5 Lakes Energy Incentive REC Presentation - 2025 Symposium

Exhibit 5 : ABATE Comments on U-15800

Exhibit 6 : Consumers Comments on U-15800

Exhibit 7 : DTE Comments on U-15800

Exhibit 8 : MEC Comments on U-15800

Exhibit 1

2025 Staff Transfer Price Schedule Update Report

U-15800 Docket Filing

2025 MPSC Staff Transfer Price Schedule

Background

The transfer price concept was originally established through legislation in 2008 Public Act 295 (PA 295) and continues to be relevant as amended by 2023 Public Act 235 (PA 235). PA 235 Section 49(3)(c) described a volumetric recovery mechanism utilizing the power supply cost recovery clause for renewable energy and capacity. This mechanism was necessary to calculate the incremental cost of compliance with PA 295 over a twenty-year period. PA 235 maintains this volumetric cost recovery mechanism but updates the twenty-year period.

The Commission's December 20, 2011, Commission Order in Case No. U-16582 directed the Michigan Public Service Commission Staff (Staff) to convene a technical conference with the following objectives:

- Address the appropriate inputs for developing transfer prices;
- Address the method for developing transfer prices; and
- Determine adequate measures to protect confidential information that recognizes the rights of the other parties to examine and test the evidence that may be used to develop transfer prices.

Staff convened the first technical conference on January 18, 2012, with DTE Electric Company (Formerly known as Detroit Edison Company), Michigan Environmental Council (MEC) and the Environmental Law and Policy Center (ELPC) to discuss inputs and the methodology for developing transfer prices and adequate measures to protect confidential information that allows for intervening parties to test the transfer price calculation methodology in the course of a contested case hearing. The parties agreed to work on solutions to the issues and provide the information electronically on February 15, 2012 and meet again on February 21 to discuss what each party had filed.

At the February 21, 2012, technical conference, Staff and MEC described the proposed transfer price calculation methodologies. The Attorney General also participated in the meeting. Additionally, processes to disclose necessary confidential information to parties yet adequately protect the data were discussed.

Staff convened a larger technical conference on May 30, 2012, with all Companies and interveners that participated in cases with transfer price issues. The goal of this larger technical conference was to try to reach consensus on a procedure to develop and update the transfer price schedules on a yearly basis. The parties attending the technical conferences provided discussion and feedback related to inputs and the methodology for developing transfer prices and measures to protect confidential information that allows for intervening parties to adequately test the transfer price calculation methodology in the course of a contested case.

U-15800 Docket Filing

Methodology

Staff's proposed methodology was to set yearly transfer price schedules that will cover the twenty-year time frame of the renewable energy planning period and Staff continues to support this methodology, believing it to be in compliance with PA 235 on a going forward basis. The transfer prices resulting from this methodology will be used by electric providers[1] as a point of reference.

Staff continues to believe 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 power purchase agreement. MCL460.1047 explains that when setting the transfer price, the Commission shall consider factors including, but not limited to, projected capacity, energy, maintenance, and operating costs, information filed under Section 6j of 1939 PA 3 (MCL 460.6j), and wholesale market data, including but not limited to, locational marginal pricing. To best determine market-based value of PA 295 and PA 235 compliant generation, Staff continues to believe that for purposes of developing the MPSC Staff Transfer Price Schedule that the levelized cost of a new natural gas combined cycle (NGCC) plant would likely be analogous to the market price mentioned above. Starting with the U.S. Energy Information Administration's (EIA) levelized cost estimate for an advanced natural gas combined cycle facility , Staff built a trend line from the cost estimate to effectively follow the value of energy, capacity and inflation through 2045 that represents the cost of a new NGCC plant in each year. The natural gas cost estimates used in this calculation were sourced from EIA's 2023 Annual Energy Outlook report, which is the most recent report available at the time of this filing.

To determine the slope of the trend line, Staff utilized data and projections provided by the EIA and the IHS Global Insight. Staff utilized fuel cost forecasts and producer price indices including utility natural gas, employment cost, industrial commodities, metals and metal products, and machinery and equipment. Consistent with common industry practice, Staff proposes that by analyzing projected construction cost components and fuel price forecasts throughout the plan period, Staff was able to calculate a proxy for market energy prices, capacity prices, ancillary benefits and the effect of inflation through the updated twenty-year plan period.

Staff believes that, given current Midcontinent Independent System Operator market conditions, the market will converge towards the price of a new NGCC plant every year. In an effort to accurately and effectively assign value to the market-based component of renewable energy generation and capacity, Staff developed this transfer price methodology so that it will result in a proxy for how a long-term power purchase agreement would be structured. This methodology is the basis for the calculation of the MPSC Staff Transfer Price Schedules.

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[1] Transfer price schedules are currently utilized by Consumers Energy Company, DTE Electric Company, Indiana Michigan Power Company, and Upper Michigan Energy Resources Corporation.

U-15800 Docket Filing

Data Protection

The Commission specified that a purpose of the technical conferences was to discuss adequate measures to protect confidential information but allows for intervening parties to adequately test the transfer price calculation methodology in the course of a contested case hearing. Staff has received permission from IHS Global Insight to allow the parties to a contested case to visit the MPSC offices and review the producer price indices used to create the trend line for Staff's transfer price schedule.

Timing

Staff will issue an updated MPSC Staff Transfer Price Schedule each spring in docket number U-15800. This is done to allow the electric providers time to incorporate the MPSC Staff Transfer Price Schedule into future renewable energy case filings for the calculation of the incremental cost of compliance.

In each contested Renewable Cost Reconciliation case, the electric provider will request a transfer price schedule be established and file its proposed transfer price schedule. Additionally, Staff will file the MPSC Staff Transfer Price Schedule.

Upon Michigan Public Service Commission approval of a transfer price schedule in the Renewable Cost Reconciliation, the transfer price schedule will be in effect until a new transfer price schedule is established in a subsequent proceeding. The most recently approved transfer price schedule will apply to all new renewable energy contracts and projects approved by the Commission until a new one is created. The most recently approved transfer price schedule will have no impact on contracts or projects that have already had transfer price schedules assigned.

2025 MPSC Staff Transfer Price Schedule

Staff presents its 2025 MPSC Staff Transfer Price Schedule. Using the same base methodology as its 2012 – 2024 MPSC Staff Transfer Price Schedules,[2] Staff updated three components. These updates include:

- Updated IHS Global Insight data.
- Updated the IHS Global Insight base year to 2029.
- Utilized Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2023 natural gas base case Henry Hub nominal gas price projection.[3]

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[2] Due to the timing of the technical conferences, the 2012 MPSC Staff Transfer Price Schedule was not filed in this docket, but only filed in Renewable Cost Reconciliation Cases No: U-16662, U-16655 and U-16656 .

[3] Staff utilized the most recent version of the AEO, from 2023, because an updated report has not yet been released by the EIA for 2024 or 2025.

U-15800 Docket Filing

- In compliance with Section 45(3) of PA 235, extended the planning period of the transfer price to match the new PA 235 20-year planning period.

The 2025 Staff Transfer Price Schedule updates resulted in an overall average decrease in transfer prices when compared to the 2024 Staff Transfer Price Schedule.

	2024 Transfer Price Schedule	2025 Transfer Price Schedule
2025	$65.60	$64.22
2026	$68.91	$67.53
2027	$70.40	$68.81
2028	$70.68	$68.83
2029	$71.47	$69.69
2030	$72.31	$70.53
2031	$73.69	$71.83
2032	$75.28	$73.27
2033	$76.86	$74.69
2034	$78.90	$76.46
2034	$80.53	$77.84
2036	$82.04	$79.15
2037	$83.72	$80.69
2038	$85.50	$82.32
2039	$87.22	$83.88
2040	$89.34	$85.78
2041	$91.43	$87.64
2042	$93.26	$89.31
2043	$95.19	$91.05
2044	$97.58	$93.14
2045	$99.97	$95.22

EXHIBIT 1

Fixed price cost escalation: Fixed portion of levelized cost with 2029 as base year (2029=1)

Variable cost price escalation: Variable portion of levelized cost is multiplied by Nat Gas price forecast index, with 2029 as a base year (i.e. 2029=1).

	FIXED Component	$37.52				**VARIABLE Component**	$32.17				
	Producer Price Index--Intermediate Materials	Producer Price Index--Industrial Commodities	Producer Price Index--Machinery & Equipment	Producer Price Index--Metals & Metal Products	Average	Producer Price Index--Utility Natural Gas	Employment Cost Index--Total Private Compensation	Weighted Average (Utility Nat Gas 70% ; Employment Cost 30%)		**2024 Transfer Price Schedule**	**2025 Transfer Price Schedule**	**Difference 2025 - 2024**
2025					35.77			28.45	**2025**	$65.60	$64.22	-$1.39
2026					36.25			31.28	**2026**	$68.91	$67.53	-$1.38
2027					36.62			32.19	**2027**	$70.40	$68.81	-$1.59
2028					36.86			31.98	**2028**	$70.68	$68.83	-$1.85
2029					37.52			32.17	**2029**	$71.47	$69.69	-$1.77
2030					38.17			32.36	**2030**	$72.31	$70.53	-$1.78
2031					38.83			32.99	**2031**	$73.69	$71.83	-$1.86
2032					39.50			33.78	**2032**	$75.28	$73.27	-$2.00
2033					40.13			34.56	**2033**	$76.86	$74.69	-$2.18
2034					40.75			35.71	**2034**	$78.90	$76.46	-$2.44
2035					41.31			36.53	**2035**	$80.53	$77.84	-$2.69
2036					41.92			37.23	**2036**	$82.04	$79.15	-$2.89
2037					42.71			37.98	**2037**	$83.72	$80.69	-$3.03
2038					43.56			38.76	**2038**	$85.50	$82.32	-$3.18
2039					44.38			39.51	**2039**	$87.22	$83.88	-$3.33
2040					45.20			40.57	**2040**	$89.34	$85.78	-$3.57
2041					46.06			41.58	**2041**	$91.43	$87.64	-$3.79
2042					46.93			42.38	**2042**	$93.26	$89.31	-$3.95
2043					47.79			43.26	**2043**	$95.19	$91.05	-$4.14
2044					48.63			44.52	**2044**	$97.58	$93.14	-$4.44
2045					49.49			45.73	**2045**	$99.97	$95.22	-$4.74
											Average	-$2.71

Levelized Cost Calculation

Factor	NGCC	*notes*
Capacity	400	MW
Loading Factor	71.00%	% of time the unit would be dispatched if available
Equivalent Avail.	87.00%	% of time the unit would be available for dispatch
Capacity Factor	61.77%	(Loading Factor)*(Equivalent Availability)
Heat Rate	6719	BTU/kWh
Fuel Cost	$4.33	$ per Million BTU
Total Cost no AFUDC	$572.033	MM
AFUDC	$78.22	MM
Total Cost	$650.250	MM
Fixed Charge Rate	11.59%	% used to calculate fixed cost recovery component
Fixed O&M	$14.62	$/kW
Annual Lev. Fixed Cost	$75.36	MM
Total Annual Lev. Fixed Cost	$81.21	MM
Fixed Cost	0.0375	$/kWh
Fuel Cost	0.0291	$/kWh
Var. O&M	0.0031	$/kWh
Total Var. Cost	0.0322	$/kWh
Total Cost	**0.0697**	$/kWh

Overnight Cost	540.0243	MM

AFUDC		Total Overnight Cost (MM) in 2021 $	Inflation Rate	Cumulative	Finance Rate
Year	GCC	$540.024	2%		6.56%
1	5%	27	27.54	27.54	1.81
2	30%	162	168.55	196.09	12.86
3	35%	189	200.58	396.67	26.02
4	30%	162	175.36	572.03	37.53
	1	540	572.033		78.22

Source: EIA Annual Energy Outlook 2023
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=1-AEO2023&region=0-0&cases=ref2023&start=2021&end=2050&f=A&linechart=~ref2023-d020623a.54-1-AEO2023&ctype=linechart&sourcekey=0

	Period (Used for Levelized Calculation)	Henry Hub Using 2023 Annual Energy Outlook (Nominal)
2025	1	3.8034
2026	2	3.4125
2027	3	3.2445
2028	4	3.2530
2029	5	3.3542
2030	6	3.5351
2031	7	3.7790
2032	8	4.0742
2033	9	4.4423
2034	10	4.7518
2035	11	5.0162
2036	12	5.1489
2037	13	5.3260
2038	14	5.6316
2039	15	5.6396
2040	16	5.9925
2041	17	6.2577
2042	18	6.3872
2043	19	6.4293
2044	20	6.5164
2045	21	6.6630

Discount Rate	8.98%
Net Present Value Fuel	$40.25
Levelized Fuel Price	$4.33

Exhibit 2

MPSC Staff Presentation - 2025 Symposium

EXHIBIT 2

Transfer Price & On-Peak Demand

2025 Symposium

June 5, 2025

Jesse Harlow
Renewable Energy Section Manager

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

Schedule

10:00am – 12:00pm

- ❑ Transfer Price Past & Present
  - → MPSC Staff - Jesse Harlow
  - → MEC - Douglas Jester
- ❑ General Discussion
- ❑ Break for Lunch

1:00pm – 3:00pm

- ❑ On-Peak Definition & Incentive RECs
  - → MPSC Staff - Jesse Harlow
  - → MEC - Douglas Jester
- ❑ General Discussion
- ❑ Next Steps & Closing Remarks

Presentations available at MPSC website: *Renewable Energy Standards & Plans*

https://www.michigan.gov/mpsc/commission/workgroups/2023-energy-legislation/renewable-energy-standards-and-plans

EXHIBIT 2

Transfer Price Past & Present

Presented by Jesse Harlow, MPSC Staff

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

Transfer Price Purpose

Renewable Energy Cost

=

Transfer Price

+

Incremental Cost of Compliance

- Enables calculation of the Incremental Cost of Compliance (ICC)
  - → Isolates any additional cost of renewable energy
- Approximates the cost of non-renewable generation
- Transfer price (TP) schedule approved annually
  - → Filed in Renewable Energy Plan (REP) Reconciliations
  - → Most recent TP schedule is applied for the duration of a contract

Transfer Price History

EXHIBIT 2

- PA 295 of 2008
  - → Mandates the ICC
- Defined by Dec. 4, 2008 Order in U-15800
  - → ICC via Transfer Price
- Utilities calculate TP independently
  - → 2009 - 2011
- Symposium held in Feb. 2012
  - → Developed the current methodology
  - → Staff TP schedule filed Spring of each year in U-15800

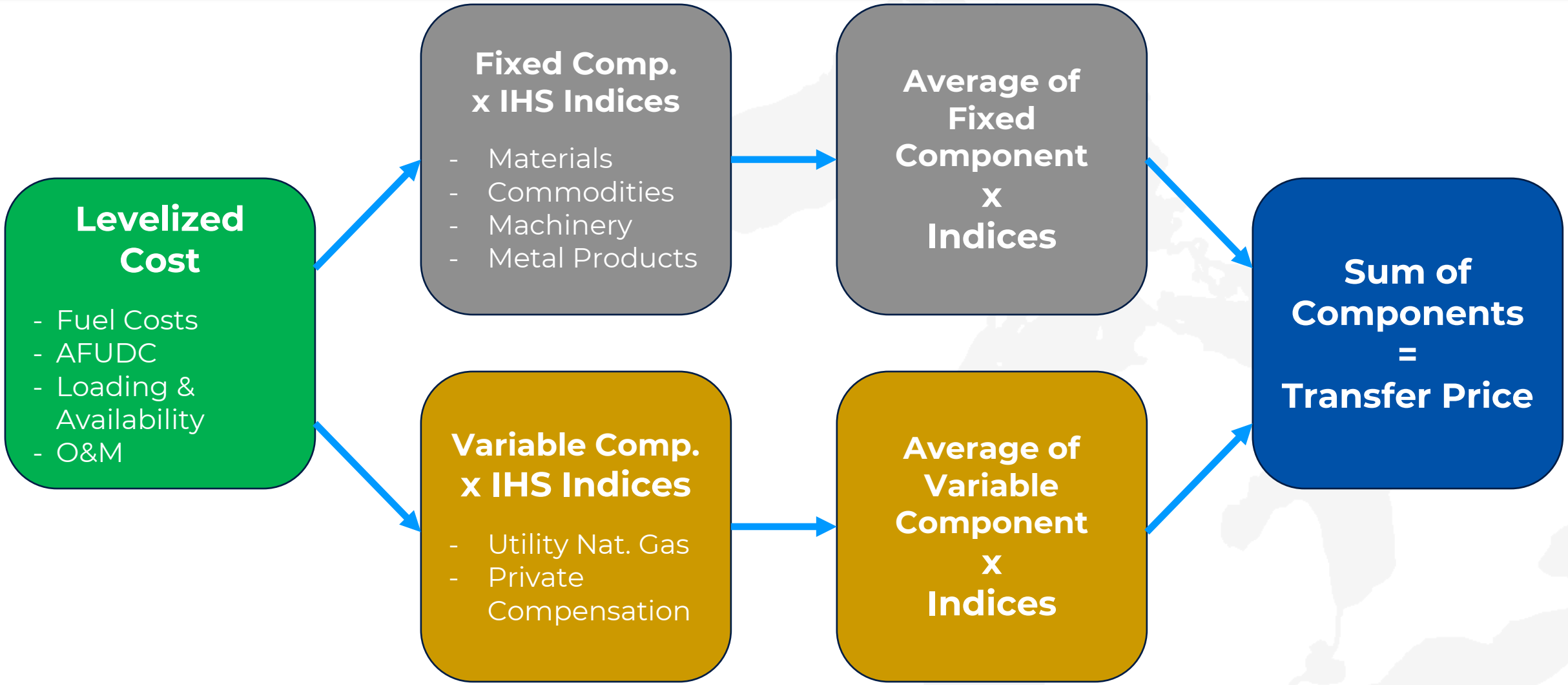
Staff Transfer Price: Current Methodology

EXHIBIT 2

- Generic non-renewable generation
  - → Natural Gas Combined Cycle (NGCC)
  - → Long Term PPA sets market price
- Cost estimated using:
  - → Levelized cost
    - Construction Funds (AFUDC)
    - Henry Hub Natural Gas
    - O&M
  - → IHS Indices

Transfer Price Calculation

EXHIBIT 2



Detailed methodology published to MPSC Docket U-15800.

U-21662 Testimony on Transfer Prices

EXHIBIT 2

- Clean Energy Standard
  - → PA 235 Section 51
  - → 80% by 2035, 100% by 2040
- Carbon Capture & Storage (CCS)
  - → 90% efficacy for natural gas generation
- Intervenors call for inclusion of CCS in the transfer price

Conclusion & Next Steps

EXHIBIT 2

Pursuant to Commission Order in U-21662

Date	Event
June 5, 2025	• 2025 Symposium • Gather input from all parties
June 20, 2025	• File initial comments to U-15800
August 1, 2025	• Post draft report on Transfer Price and on-peak to MPSC website: *Renewable Energy Standards and Plans* • File comments on draft report to U-15800
September 1, 2025	• File final report by MPSC Staff

Questions

Presentation by Douglas Jester, MEC

General Discussion

Lunch Break
Reconvene at 1:00 PM

On-Peak Definition & Incentive RECs

Presented by Jesse Harlow, MPSC Staff

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

On-Peak Definition History

EXHIBIT 2

Pursuant to Commission Temporary Order in U-15800

- December 4, 2008
  - → Established REP filing guidance
  - → Pursuant to PA 295 of 2008
- U-15800 Section XI
  - → Consistent with MISO peak demand times
  - → 0600 - 2200 EST
  - → Monday - Friday
  - → Excludes holidays
- Necessary for calculating Incentive RECs pursuant to MCL460.1039(b) & (c)

U-21662 On-Peak Testimony

EXHIBIT 2

- Michigan Environmental Council (MEC) testimony
  - → Peak demand has shifted
  - → Definition should be updated
  - → Definition should align with current peak billing practices

Questions

Presentation by Douglas Jester, MEC

General Discussion

Conclusion & Next Steps

EXHIBIT 2

Pursuant to Commission Order in U-21662

Date	Event
June 5, 2025	• 2025 Symposium • Gather input from all parties
June 20, 2025	• File initial comments to U-15800
August 1, 2025	• Post draft report on Transfer Price and on-peak to MPSC website: *Renewable Energy Standards and Plans* • File comments on draft report to U-15800
September 1, 2025	• File final report by MPSC Staff

Exhibit 3

5 Lakes Energy Transfer Price Presentation - 2025 Symposium

EXHIBIT 3

Renewable Energy Plan Transfer Prices After 2023 PA 2035

Douglas Jester, Managing Partner
5 Lakes Energy
djester@5lakesenergy.com

www.5lakesenergy.com

EXHIBIT 3

In 2023, Michigan adopted Updated Renewable and New Clean Energy Standards

- PA 235 establishes the following standards for each electricity provider, including regulated investor-owned utilities, municipal utilities, cooperative utilities and alternative energy suppliers:
  - Renewable energy must be 15% of sales each year through 2029
  - Renewable energy must be 50% of sales each year 2030 through 2034
  - Renewable energy must be 60% of sales each year 2035 and thereafter
  - Clean energy must be 80% of sales each year 2035 through 2039
  - Clean energy must be 100% of sales each year 2040 and thereafter.
  - I&M and Wolverine have carve-out provisions because current or contracted nuclear generation exceeds 40% of sales, so their renewables only need to cover the balance of their sales.
- These standards do not prevent generation in Michigan that is not renewable or not clean.

EXHIBIT 3

In 2023, Michigan adopted Updated Renewable and New Clean Energy Standards

- Renewable energy consists of wind, solar, hydropower, and certain categories of biomass or biogas-fueled electricity generation.
  - Can be anywhere in the customer's RTO
  - Renewable energy credits (RECs) can be separated from power and transferred for compliance and have a shelf-life of 5 years
  - Only 5% of compliance can be stand-alone out-of-state RECs, but unlimited RECs can be out-of-state RECs bundled with capacity credits used in meeting resource adequacy standards
- Clean energy consists of non-emitting sources (wind, solar, hydropower, nuclear) or gas-fueled generation with carbon capture and storage that is 90% effective in reducing emissions from the gas plant.

EXHIBIT 3

Michigan Utilities Have No Need for New Gas Plants without CCS

Assume announced retirements and conversions and current capacity factors for other existing plants:

	Annual MWh			
	2024	2030	2035	2040
Sales (2% AGR)	98,831	111,300	122,884	135,674
Required Renewables	14,825	55,650	73,730	81,404
Required Clean	-	-	98,307	135,674
Existing Renewables	15,416	15,416	15,416	15,416
Incremental Renewables Needed	(591)	40,234	58,314	65,988
Existing Clean	39,667	39,667	39,667	39,667
Incremental Clean Needed inc Renewables	(39,667)	(39,667)	58,640	96,007
Incremental Clean Needed Not Necessarily Renewable	(39,076)	(79,901)	326	30,019
Losses (can be not-Clean)	7,906	8,904	9,831	10,854
Room for non-Export not-Clean	91,913	64,554	34,407	10,854
Continuing Gas	56,039	56,039	56,039	56,039
Continuing Other Fossil Generation	28,186	8,500	2,000	2,000
Existing Plants Excess Not-Clean	(7,688)	(15)	23,632	47,185

EXHIBIT 3

What new resource is avoided by new renewables?

- Other new renewables?
- New nuclear?
- New gas with CCS?

EXHIBIT 3

What is the appropriate basis for the transfer price?

- If a utility will only add renewables, then the cost of renewables is the transfer price and there is no incremental cost of compliance
- Gas with CCS is currently available and apparently less costly than new nuclear
- If a utility will add something besides renewables, cost of gas generation with CCS should be the transfer price

EXHIBIT 3

What is the cost of gas with CCS?

- Utilities can still use combustion turbines without CCS as a rarely-used capacity resource, so net CONE based on CT is the avoided cost of capacity
- EPA calculated the cost of CCS for a combined cycle plant as part of 111(b) rule-making
  - That cost, plus inflation since 2019, is $22.66 per MWh. This amount should be added to the energy portion of the transfer price computed for a CC in Staff's usual method.

www.5lakesenergy.com

Exhibit 4

5 Lakes Energy Incentive REC Presentation - 2025 Symposium

EXHIBIT 4

Renewable Energy Plan
Incentive RECs Revisited

Douglas Jester, Managing Partner
5 Lakes Energy
djester@5lakesenergy.com

5lakes energy
www.5lakesenergy.com

EXHIBIT 4

In 2023, Michigan Adopted Updated Renewable and New Clean Energy Standards

- PA 235 establishes the following standards for each electricity provider, including regulated investor-owned utilities, municipal utilities, cooperative utilities and alternative energy suppliers:
  - Renewable energy must be 15% of sales each year through 2029
  - Renewable energy must be 50% of sales each year 2030 through 2034
  - Renewable energy must be 60% of sales each year 2035 and thereafter
  - Clean energy must be 80% of sales each year 2035 through 2039
  - Clean energy must be 100% of sales each year 2040 and thereafter.
  - I&M and Wolverine have carve-out provisions because current or contracted nuclear generation exceeds 40% of sales, so their renewables only need to cover the balance of their sales.
- These standards do not prevent generation in Michigan that is not renewable or not clean.

EXHIBIT 4

In 2023, Michigan Adopted Updated Renewable and New Clean Energy Standards

- Renewable energy consists of wind, solar, hydropower, and certain categories of biomass or biogas-fueled electricity generation.
  - Can be anywhere in the customer's RTO
  - Renewable energy credits (RECs) can be separated from power and transferred for compliance and have a shelf-life of 5 years
  - Only 5% of compliance can be stand-alone out-of-state RECs, but unlimited RECs can be out-of-state RECs bundled with capacity credits used in meeting resource adequacy standards
- Clean energy consists of non-emitting sources (wind, solar, hydropower, nuclear) or gas-fueled generation with carbon capture and storage that is 90% effective in reducing emissions from the gas plant.

EXHIBIT 4

2023 PA 235 Retained Incentive RECs for Compliance with the RES

- 2 RECs per MWh solar from a system approved before April 20, 2017
- 1/5 RECs per MWh from renewable energy other than wind at peak demand times determined by the commission.
- 1/5 RECs per MWh generated during off-peak hours, stored, and used during peak hours.
- 1/10 RECs per MWh generated during 1st 3 years operation if constructed using equipment made in Michigan.
- 1/10 RECs per MWh generated during 1st 3 years operation if constructed using Michigan workforce.

EXHIBIT 4

2023 PA 235 Retained Incentive RECs for Compliance with the RES

- MPSC adopted **temporary** guidance for incentive RECs in 2008 Order in Case No. U-15800
- In the 2008 Order, peak demand time was defined as: the period of time between 0600 hours EST through 2200 hours EST, Monday through Friday except holidays.
- MPSC should reconsider this definition of peak demand time, for both the non-wind peak demand incentive and the storage incentive

EXHIBIT 4

Peak Demand Time Incentive RECs Should Reflect Grid Value

Grid value of generation is currently measured by locational marginal price of energy and by accredited capacity, and no other metrics. Avoided transmission costs would be an appropriate value, but front-of-meter generation does not reduce transmission charges.

EXHIBIT 4

Locational Marginal Price will quickly evolve away from solar

The following LMP heat maps are 5 Lakes Energy modeling results, assuming renewable build out approximately matching filed utility renewable energy plans and non-renewable resources from filed utility IRPs, and assuming EIA AEO gas prices.

Details of these results are disputable. Qualitative features are virtually certain.

Daytime locational marginal prices will be suppressed by planned solar development. Incentive RECs are not warranted for all daytime renewable generation from non-wind resources

EXHIBIT 4

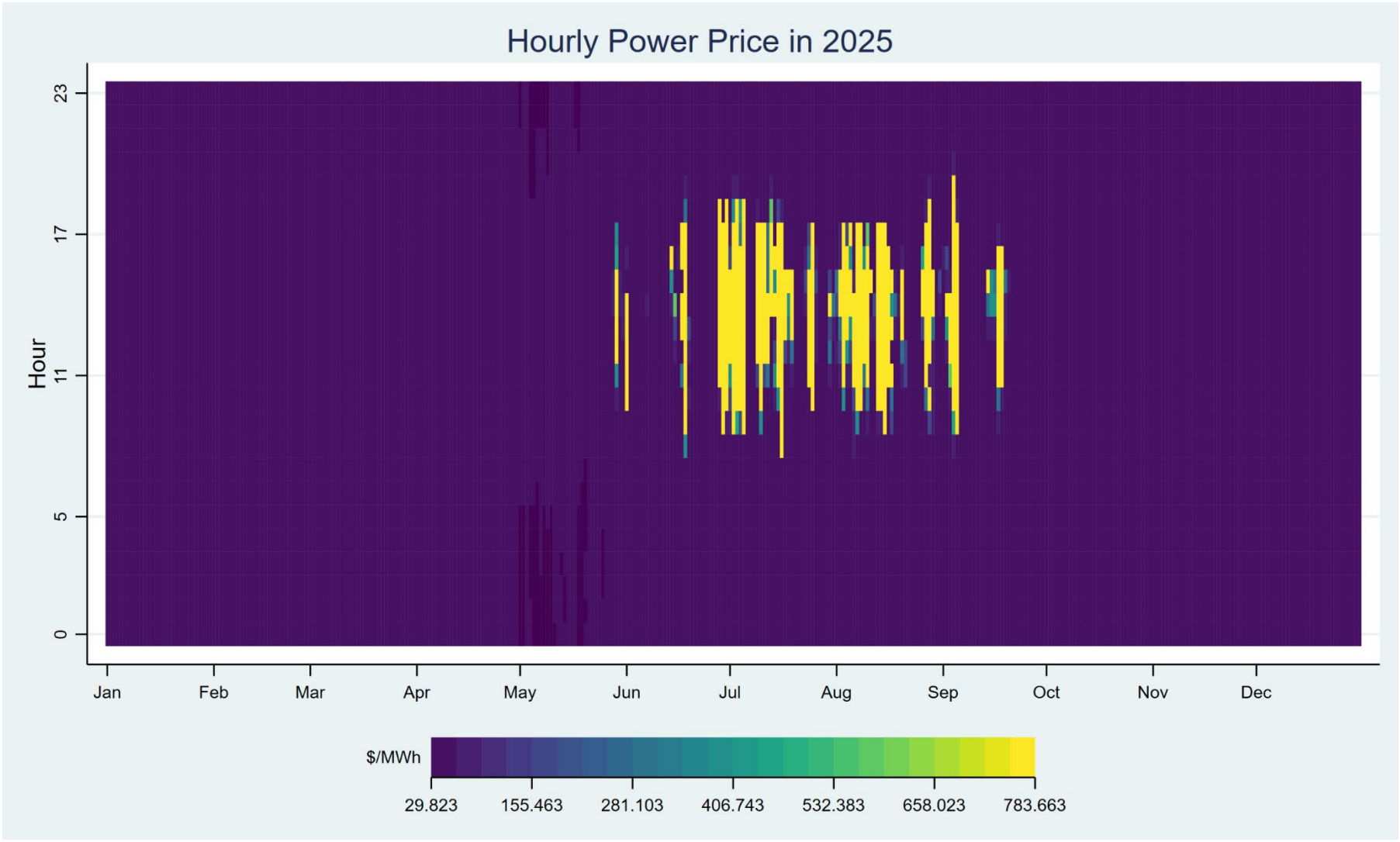
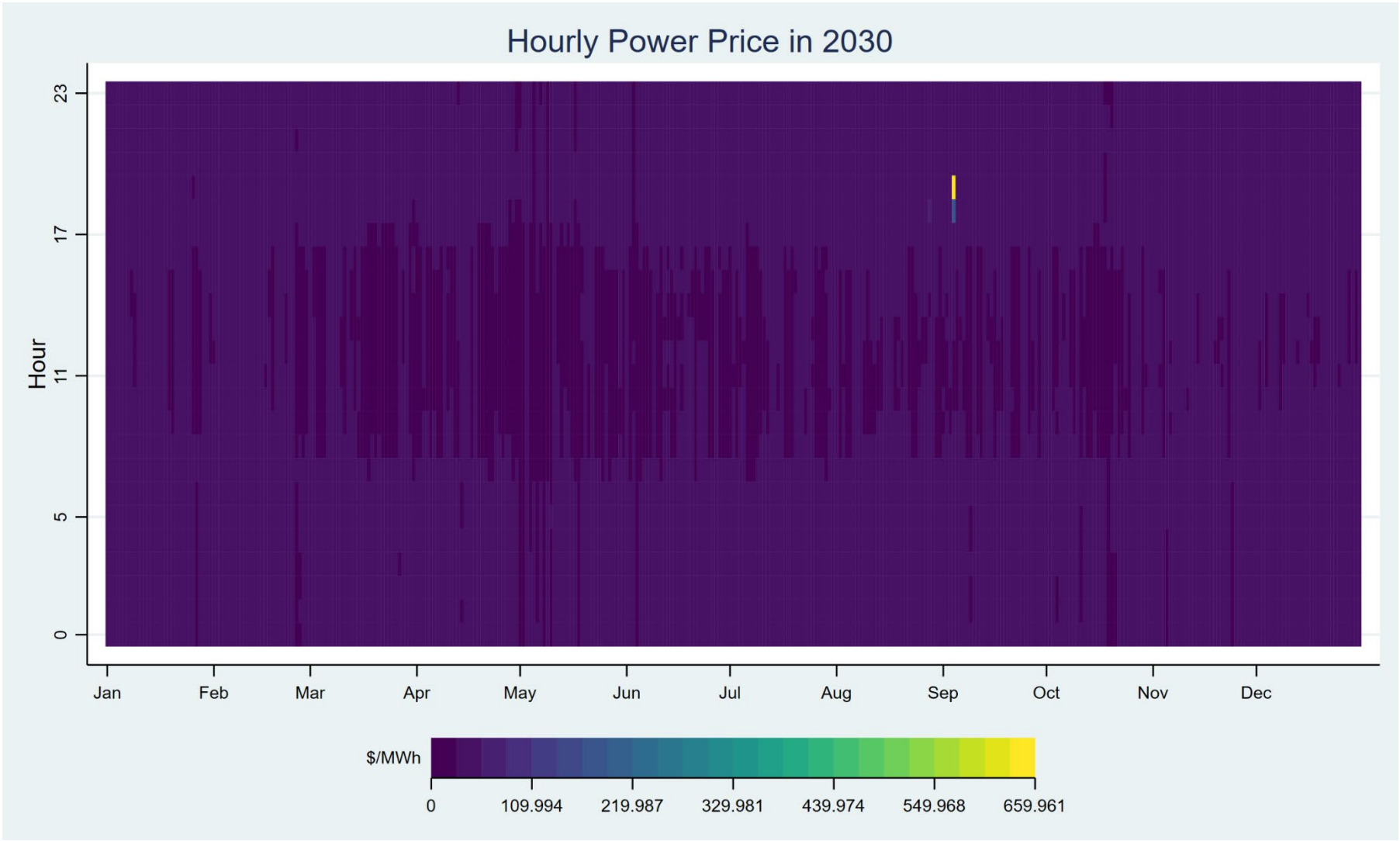

Hourly Power Price in 2025
Hour
0
5
11
17
23
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
$/MWh
29.823
155.463
281.103
406.743
532.383
658.023
783.663

EXHIBIT 4


Hourly Power Price in 2030
Hour
0
5
11
17
23
Jan
Feb
Mar
Apr
May
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Jul
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$/MWh
0
109.994
219.987
329.981
439.974
549.968
659.961

EXHIBIT 4

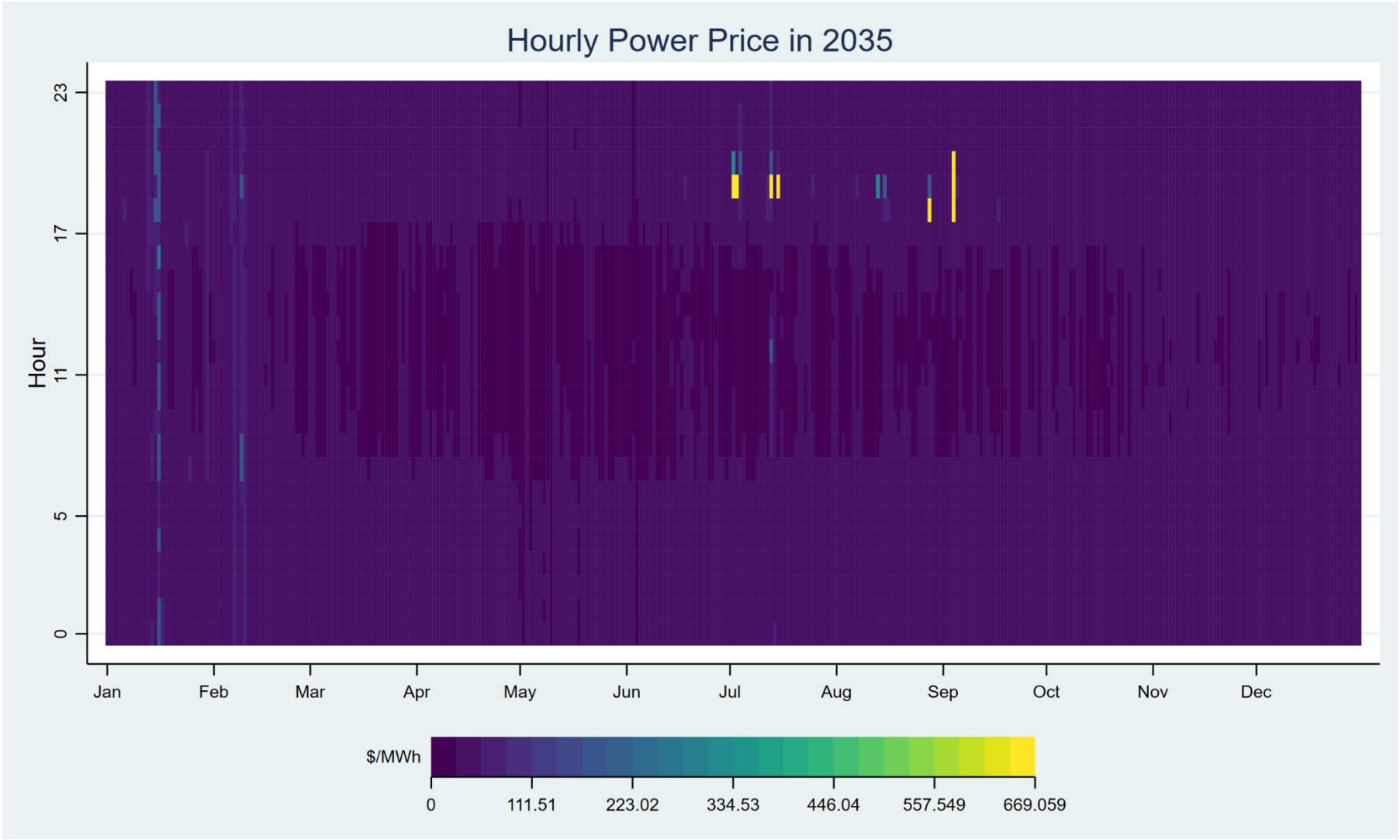
Hourly Power Price in 2035
Hour
0
5
11
17
23
Jan
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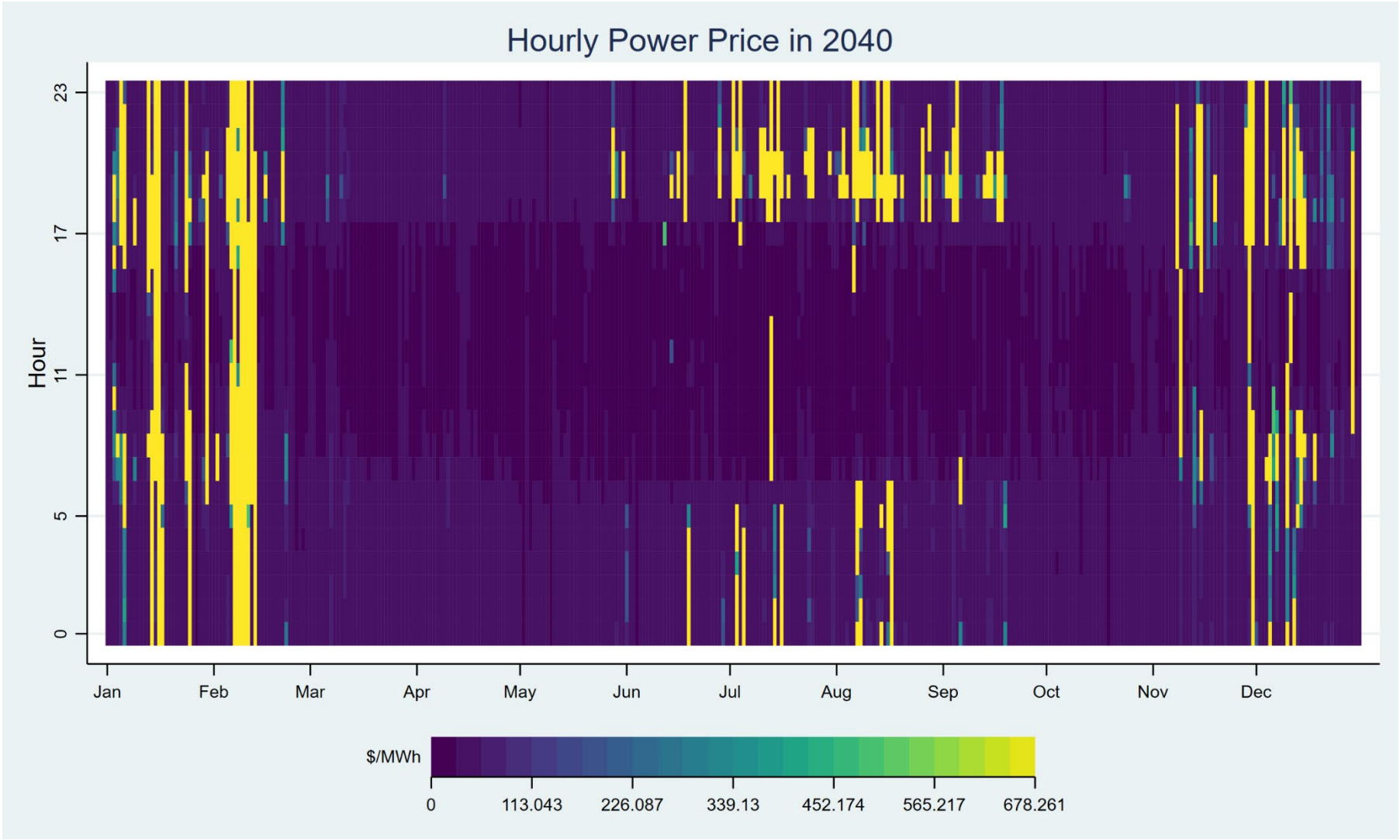
EXHIBIT 4


Hourly Power Price in 2040
Hour
0
5
11
17
23
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
$/MWh
0
113.043
226.087
339.13
452.174
565.217
678.261

Capacity Accreditation has already changed

MISO has changed capacity accreditation to a seasonal construct with direct loss of load methods of accreditation.

MISO's PY 2025-2026 wind and solar accreditation report bases solar accreditation on the hours ending 15, 16, and 17 Eastern **Standard** Time from March through November and the hours ending 8, 9, 19, and 20 EST from December through February.

Presumably, the accreditation of hydropower, biomass, and biogas will be based on approximately the same times.

Capacity Accreditation has already changed

Those hours were chosen based on the 8 hours of MISO peak loads by season in 2022 through 2024 (all of which were on weekdays).

	Count of Hours in EST of MISO Seasonal Peak Demand 2022-2024										
	HE 7	**HE 8**	**HE 9**	**HE 13**	**HE 14**	**HE 15**	**HE 16**	**HE 17**	**HE 18**	**HE 19**	**HE 20**
January		7	3				1			5	
February		3	1								
March	2										
April											
May						2	11	8	1		
June						1	2				
July						1	10	1			
August						2	6	1			
September				1	1	2	17	1			
October							2				
November											
December			1						2		1
Annual	2	10	5	1	1	8	49	11	3	5	1

EXHIBIT 4

Proposed Storage Incentive RECs

Under the temporary 2008 Order in U-15800, storage incentive RECs were based on the assumption that all renewables generation at the time of charging/pumping were preferentially used for storage, so incentive RECs were based on the lesser of renewable generation and charging/pumping in each hour. Then, to the extent that discharge was within the peak demand period, incentive RECs were credited.

My testimony in DTE's 2024-5 AREP was that this is unreasonable and that because wind, solar, and hydropower are dispatched early in merit order, any pumping/charging is supplied by non-renewable resources unless renewables are being curtailed. DTE disagreed.

The settlement is that we both recommend to the Commission that renewable credits be placed into storage in proportion to the share of renewables in generation in the hour in which charging/pumping occurs.

www.5lakesenergy.com

Exhibit 5

ABATE Comments on U-15800

Clark Hill

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June 20, 2025

VIA ELECTRONIC CASE FILING

Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, Michigan 48917

Re: Case No. U-15800 – In the matter, on the Commission's own motion, to implement 2008 PA 295 through issuance of a temporary order as required by MCL 460.1191.

Dear Executive Secretary:

Enclosed for filing please find the ***Association of Businesses Advocating Tariff Equity's Initial Comments on the Transfer Price Mechanism*** in the above-referenced matter.

Sincerely,

CLARK HILL PLC

Stephen A. Campbell

Digitally signed by: Stephen A. Campbell
DN: CN = Stephen A. Campbell email = SCampbell@clarkhill.com C = US O = Clark Hill PLC
Date: 2025.06.20 15:02:40 -04'00'

Stephen A. Campbell

SAC/lkd
cc: Parties of Record

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion to implement 2008 PA 295 through issuance of a temporary order as required by MCL 460.1191.	))))	Case No. U-15800

INITIAL COMMENTS ON THE TRANSFER PRICE MECHANISM BY THE ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

I. Background

Michigan Public Act 295 of 2008 ("PA 295") established the state's foundational renewable energy and energy optimization requirements. PA 295 created a Renewable Portfolio Standard ("RPS") for electric providers, set targets for renewable energy procurement, and authorized cost recovery mechanisms to support compliance. In 2023, Public Act 235 ("PA 235") amended and updated PA 295, reflecting Michigan's evolving clean energy policy landscape and introducing new standards and compliance obligations for utilities.

The legislation provides mechanisms for utilities to recover the costs of renewable energy investments, including the use of a Transfer Price to allocate costs between the Power Supply Cost Recovery ("PSCR") mechanism and the Renewable Energy Plan ("RE Plan"). In setting the Transfer Price, MCL 460.1047(2) requires the Michigan Public Service Commission ("Commission") to determine an electric provider's incremental cost of compliance ("ICOC") with the RPS. In doing so the Commission must determine the sum of certain costs, and subtract from that sum certain additional costs, including "[r]evenue derived from the provision of renewable energy to retail electric customers subject to a power supply cost recovery clause." MCL 460.1047(2)(b)(iv). In determining that revenue, the Commission must annually establish a price per megawatt hour considering factors "including, but not limited to, projected capacity, energy,

maintenance, and operating costs; information filed under section 6j of 1939 PA 3, MCL 460.6j; and information from wholesale markets, including, but not limited to, locational marginal pricing [("LMP")]." In Case No. U-21816 Commission Staff testified that the Transfer Price is meant to represent what a Michigan electric provider would pay if it were to obtain energy and capacity from the market through a long-term power purchase agreement ("PPA").[1]

The current Transfer Price method represents the levelized cost of a proxy non-renewable generating resource, specifically a natural gas combined cycle plant ("NGCC"), over a specified period (typically 20 years), based on Staff's assumption that PPA prices would converge toward the market pricing set by an NGCC.[2] As noted above, the Transfer Price is used to recover the costs of renewables, while any costs above the Transfer Price represent the ICOC, which is recovered by drawing down the regulatory liability balance or, if necessary, through a revenue recovery mechanism that is designed consistent with the production allocation approved in the electric provider's most recent general rate case. See MCL 460.1045-460.1049.

II. Amended RE Plan cases and the Transfer Price.

Following PA 235, utilities are required to update their RE Plans and compliance filings to reflect new statutory requirements. The Commission retains authority to review and approve cost recovery, Transfer Price schedules, and compliance methodologies. Consistent with the approach to first establish Staff's Transfer Price method, and now taken here, the Commission may convene stakeholder workgroups to consider further updates to Transfer Price calculations and other compliance mechanisms as technologies and market conditions evolve.

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[1] Case No. U-21816. Rebuttal Testimony of Jesse Harlow at page 2, lines 15-19.

[2] *Id*.

DTE Electric Company ("DTE") and Consumers Energy Company ("Consumers")'s Amended RE Plan projections, filed in Case Nos. U-21662 and U-21816 respectively, continued to use Staff's NGCC methodology for calculating the Transfer Price. However, actual Transfer Price schedules will be determined and approved by the Commission in the utilities' annual RE Plan reconciliation filings. See MCL 460.1049. In the context of Case No. U-21662, this symposium and workgroup were established to evaluate the calculation of Transfer Prices and address whether it remains reasonable to rely on a NGCC proxy price to determine the Transfer Price.

III. Party positions regarding the continued use of a NGCC to determine the Transfer Price.

In both DTE and Consumers' Amended RE Plan cases Staff testified that the current NGCC methodology is still reasonable.[3] However, Staff also noted that the proxy unit could be solar, as recent Integrated Resource Plans ("IRPs") have overwhelmingly picked solar resources to meet the generation requirements in the Preferred Course of Action ("PCA").[4] Staff asserted that it believes using solar as the proxy resource would likely reduce the Transfer Price relative to the current method.[5]

The Michigan Environmental Council and Natural Resources Defense Council ("MEC-NRDC") proposed an adder of $22.66/MWh for the cost of Carbon Capture and Storage ("CCS") to Staff's NGCC price, arguing that if NGCC remains the proxy non-renewable resource, it will

[3] *Id.* at lines 5-8, 11-23, and page 3, lines 1-10. See also Case No. U-21662, Rebuttal Testimony of Jesse Harlow at page 2, lines 1-15.

[4]Case No. U-21816, Rebuttal testimony of Jesse Harlow at page 5, lines 6-13.

[5] *Id.* at lines 13-14.

be required to have CCS to comply with the Clean Energy Standard ("CES") in PA 235, as well as federal regulations.[6]

Staff, DTE, Consumers, and ABATE argued that it was unnecessary to change the Transfer Price methodology at this time. Specifically, ABATE opposed adding the cost of CCS to the current Transfer Price methodology for the following reasons:

1. *CCS Technology Readiness*: CCS technology, while recognized as compliant with Michigan's new CES, is still in its infancy and not widely used in the energy industry. Consumers' own IRP and testimony confirmed that CCS and similar technologies were not included in resource modeling because their technical readiness and costs are not yet comparable to other power generation technologies and would not be economically selected by the model. There is no indication that CCS would be implemented by a Michigan utility, or that the cost associated with a NGCC with CCS would represent what a Michigan electric provider would pay if it were to obtain energy and capacity from the market through a long-term PPA, in the near term or before the next Amended RE Plan is filed.
2. *Economic and Practical Barriers*: There are significant barriers to CCS implementation including high capital investments, space requirements, efficiency losses (unit output reductions of 15-20%), and the current lack of economic viability at scale. These barriers, as identified by Consumers and the EPA (as discussed further below), along with additional entities, remain unresolved and make it unreasonable to include CCS costs in the Transfer Price at this time.

[6] See the Direct Testimony of Douglas Jester in Case Nos. U-21816 (pages 10-15) and U-21662 (pages 17-21).

3. *Regulatory and Planning Context*: The CES does not require 100% clean energy until 2040, and utilities are not required to file Clean Energy Plans until 2028. The current reference technology for cost benchmarking in the Midcontinent Independent System Operator ("MISO") market remains a natural gas advanced combustion turbine, not a CCS-equipped plant. MISO is only in the early stages of considering whether to change the reference technology, and any such change would require broad stakeholder input and regulatory review.
4. *Potential Ratepayer Impacts and Cost Allocation Issues*: Increasing the Transfer Price by adding CCS costs would artificially reduce the ICOC and could affect the regulatory liability balance, potentially impacting how funds are returned to customers. This significant change in cost allocation methodology requires further consideration.

IV. Symposium and Transfer Price alternatives.

As part of a settlement agreement in DTE's Amended RE Plan case (U-21662), a symposium was convened to discuss whether changes to the Transfer Price mechanism are warranted. Alternatives discussed at the symposium included the following:

1. Maintaining the current Transfer Price methodology based on the cost of a NGCC resource without CCS.
2. Adding CCS to the NGCC cost as proposed by MEC-NRDC.
3. Using a NGCC resource with optionality for CCS (i.e., allowing flexibility between NGCC with CCS or just NGCC depending on the projected regulatory liability or asset balance).
4. Using a renewable resource like solar, with the cost based on IRP-selected solar resources.
5. Eliminating the Transfer Price mechanism and recovering costs in base rates like any other production resource.

V. Comments on potential alternatives for the Transfer Price.

A. Recovering the cost of implementing a RE Plan and phasing out the Transfer Price approach.

As Staff acknowledged during the symposium, and as evidenced by the statutory structure of PA 295, the initial intent of the statute was to account for the excess costs of pursuing renewables to comply with RPS requirements. However, if utilities are largely adding renewables for both RPS compliance and supply needs generally, then the cost of the renewables is the Transfer Price. Therefore, if compliance with RPS standards is now the more cost-effective course for utilities, there may be little, if any, marginal incremental cost for complying with the RPS and, thus, little need for the Transfer Price approach at all.

While Staff explained that it favored the Transfer Price approach as an "innocuous way to fund the renewable program" and smooth the cost of RPS compliance, it is worth considering simply permitting electric utilities to recover the cost of complying with the RPS requirements in base rates, so long as costs are classified correctly between demand and energy and allocated accordingly. As Staff acknowledged during the symposium, because the cost of renewable resources has generally declined relative to the cost of the traditional fossil resources like the NGCC resource, the ICOC has declined, or even become negative. A negative ICOC increases the regulatory liability balance.

Alternatively, and taking a broader view, it may be prudent to simply set the Transfer Price at the amount necessary to eliminate the utilities' regulatory liabilities—i.e., temporarily tie the Transfer Price to the cost of implementing a RE Plan focusing on ensuring utilities do not over-recover such that refunds are ultimately necessary. During the symposium Staff stated its position that the Commission has great latitude in setting the Transfer Price, and suggested it would be most appropriate to simply set the Transfer Price at the level necessary to support the RE Plans. Rather

than searching out a proxy resource for determining an ICOC which may no longer actually exist, this approach may be prudent to more accurately reflect the RE Plan costs it is reasonable for the utilities to recover and draw down utilities' regulatory liabilities to avoid over-recovery.

B. Maintaining the Current Transfer Price methodology.

If the Transfer Price approach is maintained, it is not unreasonable to continue the current Transfer Price method of using a NGCC proxy resource at this time. The current approach ensures the utility recovers its actual cost of service associated with renewable generation resources, maintains a reasonable regulatory liability balance without the need for a RE Plan surcharge or credit, and appropriately distinguishes between capacity- and energy-related costs when PSCR costs are reflected in base rates in a rate case.

C. Addition of CCS costs to the Transfer Price.

It is premature to add the cost of CCS to the existing Transfer Price mechanism. Michigan legislation does not require that the Transfer Price be based on a non-renewable resource in the first instance, and instead merely provides the non-exclusive list of factors for the Commission to consider as set out above. Further, CCS is not required for NGCC resources until 2040 per the CES and is not widely used at this time. Indeed, as of December 2023, the Congressional Budget Office ("CBO") reported that only fifteen CCS facilities were operating in the United States,[7] and these facilities are plants that process natural gas or produce ethanol for fuel or ammonia for fertilizer - not power plants.[8] There is no evidence that CCS will soon overcome the barriers to use that currently exist. Specifically, there is no indication Michigan utilities will pursue CCS, and there is

[7] Case No. U-21816, ABATE's Revised Exhibit AB-5 at page 2.

[8] *Id.* at 5.

no evidence indicating that a Michigan utility's current cost "if it were to obtain energy and capacity from the market through long-term [PPAs]" would be a NGCC with CCS.

Indeed, no participant in the symposium identified any NGCC CCS project being undertaken in Michigan. Specifically, DTE noted that while the Transfer Price is meant to reflect the cost of an alternative technology in the year the Transfer Price is set, it hadn't found good examples of CCGT with CCS. Further, despite its proposal, MEC-NRDC acknowledged that it wasn't aware of the utilities which were using CCS, instead simply pointing to the EPA's report accompanying its rule 111(b) rulemaking determining CCS was available, which MEC-NRDC stated it was relying on, rather than making its own plan.

Given the basis for this recommendation, it's worth noting that the EPA recently proposed repealing the rule establishing CCS-based standards for new base load stationary combustion turbines:[9]

> [T]he EPA is proposing that 90 percent CCS is neither adequately demonstrated nor cost-reasonable for new base load combustion turbines. Furthermore, because it is extremely unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, the EPA is proposing to determine that the phase 2 standards of performance in the CPS for new base load combustion turbines are not achievable. The contrary determinations in the CPS appear to be in error for many of the same reasons that apply to existing coal-fired steam generating units. Consequently, the EPA is proposing to repeal the phase 2 CCS-based requirements for new base load stationary combustion turbines.

The suggestion that the cost of the most likely alternative resource should be that of a NGCC with CCS is therefore inconsistent with the current adoption (or, as is the case here, evidenced lack thereof) and the future likelihood of CCS serving that role. While Michigan electric providers can meet the CES with a "clean energy system" that is "fueled by natural gas and uses carbon capture

[9] https://www.epa.gov/system/files/documents/2025-06/12674-01-oar_carbon-pollution-standards-repeal-nrpm_proposal_20250611_clean_v3_0.pdf

and storage that is at least 90% effective in capturing and permanently storing carbon dioxide," it can also do so with any other clean energy system. These include any facility that "[g]enerates electricity or steam without emitting greenhouse gas, including nuclear generation," or is ultimately "defined as a clean energy system in rules adopted by the commission." MCL 460.1003(i).

Given these realities, as well as the animating purpose of requiring the Commission to determine an electric provider's ICOC with the RPS, there is no reasonable basis for adding CCS costs to the Transfer Price at this time. A NGCC with CCS is not currently the most reasonable alternative to renewable resources, nor is there any evidence that Michigan utilities are pursuing that resource or would pay the costs of the same through a long-term PPA. The Transfer Price method should therefore not be modified at this time to include the significant CCS costs identified above.

D. Setting the Transfer Price based on a renewable resource pursuant to IRP PCAs.

Staff testified in Case No. U-21816 that recent IRP PCAs have overwhelmingly selected solar resources, and that a Transfer Price based on solar would most likely be lower than the Transfer Price currently calculated by Staff using a NGCC resource.[10] During the symposium Staff also acknowledged that it had internally considered utilizing a solar resource, and that currently the utilities are almost exclusively pursuing solar resources. Despite its proposal regarding a CCS adder, in its Initial Brief in Case No. U-21816 MEC-NRDC also stated that "MEC and NRDC do not oppose revising transfer prices to match the actual cost of Consumers Energy's solar

[10] See Case No. U-21816, Harlow Rebuttal at 5.

resources." As such, it may be appropriate to further consider the cost impacts of using a solar resource as the basis for the Transfer Price.[11]

VI. Cost recovery and allocation concerns.

Because the cost of renewables has fallen relative to the cost of traditional fossil resources, the ICOC has declined over the years (and has even been negative at times),[12] which increases the regulatory liability balance. By 2045, the end of the current RE Plan period, Consumers projects a substantial regulatory liability balance of $332.7 million,[13] and DTE projects a regulatory liability balance of $1.5 billion[14] based on the current NGCC methodology. Increasing the Transfer Price relative to the current method would allow utilities to over-collect for renewables to an even greater extent than they currently are, holding more ratepayer money for refund at a future time. Significantly increasing the Transfer Price may therefore necessitate a RE Plan sur-credit to ensure a reasonable level of regulatory liability balance is maintained. Increasing the Transfer Price would also increase the regulatory liability balance, which would need to be returned to customers, and allocation back to customer classes would also need to be determined. Thus, regardless of Transfer Price methodology, the Commission will need to ensure that rate-regulated electric utilities recover no more and no less than their actual cost of providing service, whether that is by maintaining the current Transfer Price and regulatory liability/asset approach, or another method.

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[11] Staff also suggested that under this approach the Transfer Price would diminish towards zero. (Harlow 4 Tr 844.) This suggests there is no longer a premium for obtaining new renewable resources, which would make the case for eliminating or phasing out the Transfer Price approach, as discussed above.

[12] See Case No. U-21816 Exhibit A-5; Case No. U-21352 Exhibit A-1; Case No. U-21662 Exhibit A-22.

[13] Case No. U-21816, Consumers' Exhibit A-5 (MRB-2).

[14] Case No. U-21662, DTE's Exhibit A-24.

Higher Transfer Prices will also recover more renewable resource costs through the PSCR process. Increasing the amount of costs collected through the PSCR Factor will over-allocate fixed, capacity-related costs to higher load factor customers, contrary to the intent of the original legislation. Indeed, during the symposium, Staff and other parties acknowledged that the RPS cost recovery mechanism was initially established and intended to allocate costs more toward residential and commercial customers. RE Plan cost recovery has already deviated from this intent through the use of the Transfer Price approach, contrasted than the previous surcharge method. Increasing the Transfer Price to include the cost of CCS would further allocate a much greater portion of these production capacity costs to the PSCR, thus shifting even more costs to industrial customers. Furthermore, doing so in the method proposed by MEC-NRDC, in which the CCS adder is specifically added to the energy portion of the Transfer Price, would again exacerbate this deviation from the statute's original intent even further.

VII. Conclusion.

Further increasing the Transfer Price based on tenuous assumptions regarding future resource adoption is unreasonable for the multiple reasons set out above and represents another step away from the initial intended approach to recovering utilities' RPS compliance costs. If the cost of CCS is added to the existing Transfer Price method, however (which it should not be), these costs should be classified as demand-related, rather than energy-related, as CCS costs are capital costs that do not vary with energy consumption. Ultimately cost recovery for RPS compliance should ensure utilities recover their actual costs in an equitable manner that does not result in over-recovery or misallocation. During the symposium Staff asserted that beyond statutory requirements, the Commission has significant latitude in determining the Transfer Price. A reasonable cost recovery approach should therefore achieve the following:

1. Ensure that utilities recover no more and no less than the actual cost incurred to comply with the RPS requirements.
2. Appropriately classify and allocate production costs on the basis of demand and energy and avoid inappropriately shifting production capacity costs to higher load factor customers.
3. Avoid further increasing the magnitude of over-collections from ratepayers now, which will necessitate refunds later.

For the reasons described herein, the addition of CCS costs to the current Transfer Price calculation would not align with the cost recovery objectives described above. The Transfer Price should instead result in an ICOC and cost recovery consistent with the Company's actual RPS compliance costs such that the Transfer Price approach and utilities' regulatory liabilities are eventually eliminated at the end of the compliance period. The inclusion of CCS costs at this time does not achieve that result.

Respectfully submitted,
CLARK HILL PLC

By: Stephen A. Campbell

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Date: 2025.06.20 15:04:01 -04'00'

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Date: June 20, 2024

Exhibit 6

Consumers Comments on U-15800

EXHIBIT 6

June 20, 2025

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-15800 – In the matter, on the Commission's own motion, to implement 2008 PA 295 through issuance of a temporary order as required by MCL 460.1191.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Consumers Energy Company's Comments on Transfer Price and On-Peak Definition**. This is a paperless filing and is therefore being filed only in PDF.

Sincerely,

Anne M. Uitvlugt
Phone: 517-788-2112
Email: anne.uitvlugt@cmsenergy.com

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Commission's own motion, to implement 2008 PA 295 through issuance of a temporary order as required by MCL 460.1191.	Case No. U-15800

CONSUMERS ENERGY COMPANY'S COMMENTS ON TRANSFER PRICE AND ON-PEAK DEFINITION

I. INTRODUCTION

On December 4, 2008, the Michigan Public Service Commission ("MPSC" or the "Commission") issued an order ("December 2008 Order") in Case No. U-15800 defining the calculation of the incremental cost of compliance via the transfer price to be recovered through the Power Supply Cost Recovery ("PSCR") clause. The December 2008 Order also included a definiton of peak demand time as the period of time between 0600 hours Eastern Standard Time ("EST") through 2200 hours EST, Monday through Friday excepting New Year's, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day or if the holiday occurs on a Sunday, the Monday immediately following the holiday. This definition is consistent with the Midcontinent Independent System Operator, Inc. ("MISO") Third Revised Sheet No. 110. Consumers Energy Company ("Consumers Energy" or the "Company") provides its comments below.

The Commission issued an order in Case No. U-21662 on May 15, 2025 directing Commission Staff ("Staff") to convene a symposium to evaluate the calculation of PSCR transfer prices no later than June 7, 2025. In addition, Commission also directed Staff to 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. The syposium took place on June 5, 2025 where Staff and Michigan Environmental Council delivered presentations on the Transfer Price and On-Peak Definition, and attendees provided input on these topics. Staff invited all parties to file initial comments on these topics in Case No. U-15800 by June 20, 2025. Consumers Energy provides its comments below.

II. COMMENTS

1. Transfer Price

The Company does not agree that it is necessary to modify the long-established methodology for calculation of the transfer price methodology to include a projected cost for carbon capture. The MPSC's current methodology for developing its Transfer Price Schedule is based upon the levelized cost of a new natural gas combined cycle ("NGCC") plant.

a. The current transfer price methodology provides sufficient revenue recovery for the 20-year renewable energy plan filed by the Company in Case No. U-21816. The Company projects that it will be in a regulatory liability position at the end of the current 20-year plan and an increase in the transfer price schedule would only serve to increase the amount of cost transferred to the PSCR, resulting in a greater regulatory liability position. The Company believes that it should minimize the magnitude of the regulatory liability so as to not charge customers more than necessary to serve them. Further, the Company does not believe that it should collect revenue from cutomers today in order to refund it to future customers.

b. PA 235 of 2023 requires the Company to achieve a clean energy portfolio beginning in 2035 which is equal to 80% of its sales and a clean energy portfolio equal to 100% of its sales beginning in 2040. One of the resources that qualifies as clean is a NGCC

plant with carbon capture and storage that is 90% effective in reducing emissions from the gas plant. The Company believes that it is premature to modify the transfer price calculation methodology given that gas-fueled generation with carbon capture does not currently have a high adoption nor is it required for another 10 years. The Company expects to file at least three more renewable energy plans between now and 2035 and, as such, there is plenty of time to consider changes to the transfer price methodology.

c. The Company has multiple options for recovery of its renewable energy plan costs of compliance, which include various transfer price methodologies, the ability to implement a revenue recovery surcharge, and recovery through base electric rates. Cost recovery of renewable energy plan costs of compliance through a revenue recovery surcharge or through base electric rates would be based upon the Company's production cost allocation. Cost recovery of renewable energy plan costs of compliance through higher transfer costs would be based upon a cent/kWh PSCR factor; thereby resulting in potential harm to certain customer classes.

d. The Company has not yet determined how it will meet the clean energy portfolio standard. The Company will provide its initial proposal to comply with this standard in its next Integrated Resource Plan ("IRP") filing in 2026. While the Company may propose the use of NGCC with carbon capture, it has not yet made that determination nor has it been approved by the Commission. In addition, the Company does not agree that a NGCC plant with carbon capture, renewable generation, and nuclear generation are the only resources that it may need to build in the near future. With the declining capacity accreditation for renewable energy resources as well as the decline in generation from coal-fueled generation, the Company believes that natural gas-fueled

peaking generation may also be necessary to reliably serve its customers as it transitions to its clean energy future. The Company will fully evaluate the need for alternative capacity and energy resources in its 2026 Integrated Resource Plan and, until that proceeding reaches its conclusion, it is premature to reach conclusions about potential future generation resources.

2. On-Peak Definition

The Company does not agree that there is a need to adjust the definition of on-peak. While future projections might indicate that the critical hours to be served in the day may be changing, the Company believes that the MPSC's current definition of on-peak should be reaffirmed.

a. While future projections may reflect that the availability of capacity to serve peak load during certain hours during the day is becoming more scarce, this projection is not a valid reason to change the definition of on-peak. The projected capacity deficit is a result of how generation assets receive capacity accreditation and not an issue with the definition of peak demand time, as specified in MCL 460.1039(2)(b).

b. The Company is more than 16 years into its original renewable energy plan pursuant to PA 295 of 2008 and is in the midst of its first renewable energy plan amendment pursuant to PA 235 of 2023. The Company's renewable energy plans have been modeled and implemented in accordance with Michigan's laws and Commission orders. Changing the rules governing how the Company must comply with the renewable energy credit standard at this juncture would have significant implications on the Company's ability to comply. Reduction or elimination of the millions of incentive credits that the Company has modeled in its renewable energy plan amendment could jeopardize the Company's future compliance. The elimination of

the incentive credits could require the development of more than 1,000 MW of additional solar generation or more than 800 MW of additional wind generation, thereby placing a greater strain on customer affordability.

c. The Company intends to install a significant amount of energy storage to capture renewable energy which is generated, both off-peak and on-peak, in order to meet capacity needs during the tight capacity periods which are projected in the future. In addition, these storage resources will also help the Company avoid the clipping or curtailment of renewable energy resources during both on-peak and off-peak periods. As such, there is an incentive to have sufficient renewable generation, both on-peak and off-peak, with which to charge storage, including the Ludington Pumped Storage Facility. As such, these resources necessary to charge storage to serve critical hours should be incentivized, as they are currently.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Exhibit 7

DTE Comments on U-15800

DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1279

EXHIBIT 7

Andrea E. Hayden
(313) 235-9449
andrea.hayden@dteenergy.com

June 20, 2025

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: In the matter, on the Commission's own motion, to implement 2008 PA 295 through issuance of a temporary order as required by MCL 460.1191.
MPSC Case No: U-15800

Dear Ms. Felice:

Attached are DTE Electric Company's Comments on the Transfer Price and On-Peak Definition Symposium. If you have any questions, please feel free to contact me.

Very truly yours,

Andrea E. Hayden

AEH/cdm
Attachment

Introduction

DTE Electric Company (DTE Electric or Company) appreciates the opportunity to provide initial comments on the recent Michigan Public Service Commission (MPSC or Commission) Renewables symposium on transfer price and on-peak definition. As more fully described below, DTE Electric recommends that the Commission 1) refrain from reviewing the transfer price until the next series of integrated resource plans (IRPs) have been filed and are concluded, when additional information may be available on carbon capture and storage (CCS) commercial-scale viability; 2) continue to use the current definition of "on peak" in the calculation of Incentive Renewable Energy Credits ("incentive RECs"), thereby ensuring compliance with the intent of the enabling statute; and 3) Propose a method for calculating Incentive RECs for Storage Assets that accounts for the fact that all electrical loads are supplied by a composite mix of generation resources, rather than solely by the marginal unit.

Procedural History

On May 15, 2025, the Commission approved a settlement agreement for DTE Electric's Amended Renewable Energy Plan (REP) in Case No. U-21662. As part of the settlement agreement, the parties recommended the Commission convene a symposium to evaluate the calculation of transfer prices that includes all rate-regulated electric providers by June 7, 2025. The parties also recommended that the Commission convene a work group to revise the definition of on-peak hours for determination of incentive RECs.

In the Commission's May 15, 2025, Order Approving the Settlement, the Commission found the recommendations by the parties to hold a symposium and workgroup with their respective topics to be reasonable and in public interest. On June 5, 2025, the MPSC Staff held a symposium to address these two topics. Parties to the symposium were requested to submit their initial comments on the subjects in the Case No. U-15800 docket by June 20, 2025.

Transfer Price Calculation

While DTE Electric finds potential merit in the Michigan Environmental Council's (MEC) proposal to include the cost of CCS along with the cost of a combined cycle gas turbine in the transfer price, DTE Electric believes that the transfer price calculation should be reevaluated after the conclusion of the next series of IRPs filed by the State's utilities (i.e., DTE Electric, Consumers Energy, Indiana Michigan, Upper Peninsula Company, Northern

States Power Company, Upper Michigan Energy Resources Corporation), expected in 2028. In upcoming IRP filings, the MPSC and stakeholders are likely to receive more detailed information from utilities regarding the feasibility of CCS as an option and its associated LCOE, which will inform whether adjustments to the current transfer price are warranted. Additionally, keeping the transfer price unchanged at this time will not affect customer rates, as utilities like DTE Electric are currently forecasting near-term regulatory liabilities.

On-Peak Definition

MEC's presentation at the symposium suggests that the peak demand time incentive RECs should reflect MEC's determination of grid value. MEC is proposing to revise the definition of peak demand time from the Midcontinent Independent System Operator (MISO) current definition (0600 through 2200 EST, Monday through Friday, excepting certain holidays) – a period that is MISO Board-approved – to hours currently used by MISO to accredit solar resources (with further refinement needed in the future as MISO incorporates new capacity accreditation rules). This proposal would result in a substantial decrease in the hours used to calculate incentive RECs (on summer weekdays, from sixteen hours per day to three hours per day).

The MEC proposal is flawed for at least two reasons. First, such a definition would no longer be one based on "peak demand time" as required in MCL460.1039(2)(b), but instead on peak capacity risk – which, despite MEC's suggestion, are not the same. The Michigan Legislature specifically focused on peak demand time in the authorizing legislation, a period that statutorily is focused on when Michigan customers are using the most power. Not coincidently, the statute incents non-wind renewable resources to be available to the benefit of Michigan customers during this time. This is different than MISO's focus on peak capacity risk, which addresses when the wholesale market is most at risk for lack of generation across the grid. The Commission should continue to provide incentive RECs consistent with the goals sought to be achieved by the Legislature.

Second, such a definition would suggest that the value storage provides by shifting renewable generation from off-peak to on-peak periods is exclusively related to capacity benefits and therefore would ignore other economic energy benefits such as energy arbitrage, congestion relief or ancillary services. To comply with the legislative mandate, DTE Electric recommends continuing to use the MISO definition as a broad and consistent definition that applies to all utilities within Michigan.

Incentive RECs for Storage Assets

During MEC's symposium presentation, Mr. Jester argued that storage incentive RECs are calculated under the assumption that all renewable generation available at the time of charging or pumping are preferentially directed to storage. As a result, incentive RECs are based on the lesser of renewable generation or storage charging/pumping in each hour. When discharge occurs during peak demand periods, incentive RECs are then credited accordingly.

MEC considers this approach unreasonable. Mr. Jester contends that because wind, solar, and hydropower are dispatched early in the merit order, any charging or pumping is likely supplied by non-renewable resources—unless renewable generation is being curtailed.

DTE Electric disagrees with this assertion. The suggestion that any individual or incremental load on the MISO system, including energy storage charging, is exclusively served by the marginal resource is incorrect. This is because the marginal resource represents the last unit dispatched to meet system-wide demand, not the specific source of energy for any particular load. In reality, all loads are served from a mix of resources operating on the grid at any given time, and the marginal resource only determines the market clearing price—not the physical flow of electricity. Additionally, MISO determines the marginal resource using its system-wide model (as referenced in the MISO Monthly Operations Reports cited by Mr. Jester in Case No. U-21662), but it does not—and cannot—track the specific flow of electrons from generation sources to loads or storage systems.

The assertion that it is improper to assume the Company's renewable generation is charging its storage resources—simply because another resource elsewhere in MISO is offering a higher price and may or may not be deliverable to Michigan—is inaccurate.

Conclusion

DTE Electric looks forward to continuing to work with the MPSC Staff on these topics.

Exhibit 8

MEC Comments on U-15800

June 20, 2025

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

Via E-File

RE: MPSC Case No. U-15800

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Comments by Michigan Environmental Council Regarding Transfer Prices and Peak Demand Time Incentive Renewable Energy Credit.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Christopher Bzdok
chris@tropospherelegal.com

CC: Parties to Case No. U-15800

EXHIBIT 8

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to implement 2008 PA 295 through issuance of a temporary order as required by MCL 460.1191.	Case No. U-15800

COMMENTS BY MICHIGAN ENVIRONMENTAL COUNCIL
REGARDING TRANSFER PRICES AND
PEAK DEMAND TIME INCENTIVE RENEWABLE ENERGY CREDIT

June 20, 2025

The Michigan Environmental Council (MEC) is pleased to submit these comments in follow-up to the Renewable Energy Plan Transfer Price and On-Peak Definition Symposium held June 5, 2025. MEC appreciates the consideration and attention by MPSC Staff and other stakeholders to these issues.

TRANSFER PRICES

The transfer price is the portion of renewable energy plan (REP) revenue requirements recovered through the Power Supply Cost Recovery (PSCR) clause.[1] The original theory behind the transfer price was to represent the cost of conventional generation that would otherwise have been needed without the REP.[2] Section 47 of the statute provides that the incremental cost of compliance for an REP is calculated by summing capital, O&M, financing, and other costs required to comply with the renewable energy standards, and then subtracting out certain costs, including the transfer price.[3] These provisions have been essentially the same, with only minor changes, since PA 295 of 2008.[4] The Commission establishes a transfer price for each provider in RE reconciliations after a contested case. The transfer price for each renewable resource is assigned at the time of that resource being approved by the Commission, based on the most recently approved transfer price schedule.

In Detroit Edison's 2011 biennial REP review, U-16582, the company proposed to establish new transfer prices based on market energy and capacity price forecasts from a third-party vendor. In an appeal by MEC, the Commission reversed an ALJ decision and struck Detroit Edison's

[1] MCL 460.1047(2)(b)(iv).

[2] Ex A, Staff presentation from 2012 Transfer Price Symposium.

[3] MCL 460.1047(2)(b)(iv).

[4] Compare, Section 47 in 2008 PA 295, 2016 PA 342, and 2023 PA 235.

transfer prices because the company would not provide the forecasts to parties in the case.[5] The Commission ordered Staff to convene a technical conference within 30 days to address the appropriate inputs and methodology for transfer prices, and to conclude the conference within 90 days.[6]

Staff established its transfer price methodology for that conference – dubbed the "Transfer Price Symposium."[7] Staff took the position that "Transfer Price Schedules should be a proxy for the cost to the provider of a similar long term 'non-renewable' power purchase agreement."[8] Staff therefore used the costs of power from a hypothetical natural gas combined cycle plant escalated over the period of the REP.

In DTE Electric's 2011 RE reconciliation, Case No. U-16656, the Commission adopted Staff witness Harlow's proposed transfer prices and rejected DTE's.[9] The Commission agreed with Staff that the projected costs for the type of conventional generating plant most likely to be built by most providers – a combined cycle gas plant – should be used to establish the transfer price:

> The Commission therefore finds that to develop a fair and valid schedule of transfer prices, the appropriate comparison to the cost of renewable energy is the cost of a new conventional generating facility, rather than a computation based on some combination of current and future market factors. The Staff reasonably determined that in light of the forecasted prices for natural gas, a natural gas combined cycle unit is the most likely conventional generation unit to be built in the near future by most providers.[10]

[5] Case No. U-16582, Order, December 20, 2011, pp 16-17.

[6] *Id*.

[7] Ex A.

[8] *Id*.

[9] Case No. U-16656, Order, February 20, 2014, p 8.

[10] Case No. U-16656, Order, February 20, 2014, p 8.

Staff files proposed transfer prices for informational purposes each year in Case No. U-15800. While inputs change from year to year, Staff has used the same method for developing transfer prices since 2012, and the Commission has adopted Staff's method in each case.

The current methodology needs adjustment due to changes in law – PA 235 of 2023 in particular. As Douglas Jester's attached transfer price presentation explains, PA 235 will require a new natural gas plant like the proxy plant to include carbon capture and storage (CCS).[11] PA 235 requires Michigan electric providers to achieve a clean energy portfolio of 80% of sales from 2035 through 2039 and then 100% of sales in 2040 and thereafter.[12] A clean energy portfolio means "the percentage of an electric provider's total retail electric sales consisting of clean energy or renewable energy."[13] Clean energy means "electricity or steam generated using a clean energy system."[14] A clean energy system means a generation facility or system that either generates electricity or steam without emitting greenhouse gas, or a generating plant fueled by natural gas if the plant "uses carbon capture and storage that is at least 90% effective in capturing and permanently storing carbon dioxide."[15]

Based on these requirements, any gas plant operating in Michigan past 2034 must be 90% effective in capturing and permanently storing carbon dioxide in order to count toward the clean energy standard, and 100% effective past 2040.[16] The U.S. Environmental Protection Agency has

[11] Ex B, Douglas Jester, Renewable Energy Plan Transfer Prices After 2023 PA 235.
[12] MCL 460.1051(1); Jester Direct, 4 Tr 402.
[13] MCL 460.1003(g).
[14] MCL 460.1003(e).
[15] MCL 460.1003(i)(*ii*).
[16] *Id*.

also adopted a final rule requiring new combined cycle gas plants with capacity factors over 40% to capture 90% of their carbon emissions starting in 2032.[17]

While there may be efforts to roll back the federal rule, there is no similar effort on the horizon to repeal the Michigan clean energy standard. If the transfer price methodology continues to be based on the levelized cost of a new conventional generating plant, the methodology must account for the cost of CCS.

Alternatively, if a provider will only add renewables going forward, then the transfer price should be based on the cost of those renewables. As Douglas Jester's presentation explains, in that scenario there will be no incremental cost of compliance for new approved resources. MEC supports either outcome: basing the transfer price on the existing proxy plant method but adding the cost of CCS, or basing the transfer price on a utility's actual cost of each renewable resource procured going forward.

To date, one impartial decision-maker has reviewed the evidence on these issues in detail: the Administrative Law Judge in Case No. U-21662. The PFD in that case recommended that a workgroup be convened – which has now occurred – to discuss the issue prior to further adjudication in reconciliation cases.[18] The PFD made several findings that are supportive of the position described in these comments and the attached presentation:

- This PFD agrees with MEC-SC that the current transfer price methodology likely needs to be updated to account for CCS costs or alternatively should be revisited to find a different methodology that does not rely solely on a CCGT plant as a proxy.[19]

[17] 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, 89 Fed Reg 39798 (May 9, 2024).

[18] Case No. U-21662, PFD, attached as Ex D, February 28, 2025, pp 21-34 and pp 33-34.

[19] *Id*. at 31.

- Staff's current methodology, which has largely been accepted by electric providers, utilizes the 20-year levelized cost of a new CCGT plant. However, as MEC-SC has argued, at the federal level, a new 2024 EPA final rule requires new gas plants to operate with 90% effective CCS by 2032, although that rule is the subject of a legal challenge.[20]

- At the state level, PA 235 directs that electric providers in Michigan must have a clean energy portfolio of 80% by 2035 and 100% by 2040. Under PA 235, a natural gas plant can be considered a "clean energy system," but only if it employs CCS technology that is at least 90% effective.[21]

- Given these evolving clean energy standards, any new gas-fired power plant in Michigan would require CCS in 2032 at the earliest if the EPA final rule remains in effect, and if not, then possibly by 2035 or by 2040 at the latest under PA 235.[22]

- Thus, if the transfer price methodology is based upon the hypothetical 20-year levelized cost of a new CCGT plant, then that plant will need to incorporate CCS (and its attendant costs) sometime within that 20-year period, whether initially constructed with CCS or whether retrofitted later.[23]

- This PFD is not persuaded by Staff's argument that the current methodology remains adequate because a utility could hypothetically enter a PPA involving an out-of-state CCGT plant that is not subject to Michigan's clean energy laws.[24]

MEC incorporates the findings of the PFD in U-21662 by reference in these comments.

In sum, the transfer price methodology should be revised from its current method. It should either be based on a utility's actual cost of renewables or, if it will continue to be based on a proxy conventional plant, the cost of CCS must be added.

[20] *Id*. at 31-32.

[21] *Id*. at 32.

[22] *Id*.

[23] *Id.*

[24] *Id*.

PEAK DEMAND TIME INCENTIVE RECS

Section 39(2) of Act 235 establishes incentive RECs under circumstances that include 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).[25] The Commission currently defines peak demand time as the hours of 0600 through 2200 EST, excepting weekends and some holidays. The current definition has been in place since 2008 as the result of a Temporary Order issued in this docket, U-15800, and is overdue to be revised.

The Commission opened U-15800 to implement Public Act 295 of 2008, which required it to issue a Temporary Order within 60 days of its effective date in accordance with Section 191 of PA 295.[26] Section 191(1) directed the Commission to include in the Temporary Order formats for renewable energy plans and guidelines for requests for proposals (RFP).[27] Section 191(2) directed the Commission to, within one year after the effective date of PA 295, promulgate rules for its implementation.[28] Section 191(2) deemed the Temporary Order rescinded upon promulgation of the rules.[29] The Commission filed a request for rulemaking with the State Office of Administrative Hearings and Rules (SOAHR) in October 2008[30] and submitted draft rules to SOAHR in October

[25] MCL 460.1039(2)(b).

[26] Case No. U-15800, Order, December 4, 2008, p 1 (citing Section 191 of PA 295).

[27] MCL 460.1191(1), as enacted by 2008 PA 295.

[28] Former MCL 460.1191(2).

[29] *Id*.

[30] Case No. U-15800, Order, April 27, 2010, p 1.

2009[31], but apparently the rulemaking process was not completed.[32] Section 191 has since been amended to replace the outdated PA 295 implementation requirements with the current PA 235 implementation requirements.[33]

Regarding the incentive RECs at Section 39(2)(b), which were created by PA 295 and remain unchanged, the Temporary Order states:

> The Commission, in this temporary order, defines peak demand time as: the period of time between 0600 hours Eastern Standard Time (EST) through 2200 hours EST, Monday through Friday excepting New Year's, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day or if the holiday occurs on a Sunday, the Monday immediately following the holiday. This definition is consistent with the Midwest Independent Transmission System Operator, Inc. (MISO) Third Revised Sheet No. 110.[34]

Under the current definition, solar receives a peak demand time incentive REC for every hour it operates on weekdays, with the exception of a few holidays.

The PFD in Case No. U-21662 agreed that "the definition could stand to be revised."[35] The PFD explained:

> As MEC-SC has argued, the definition of "peak demand time" for incentive RECs first set more than a decade ago in a temporary order may no longer be suitable today, and indeed, the current definition appears to have the effect of over-incentivizing solar generation for the reasons stated by MEC-SC. This PFD also notes that during cross-examination, Mr. Harlow agreed that it is likely worthwhile to revisit the definition of "peak demand time" for the purposes of incentive RECs

[31] MPSC Report on the Implementation of Public Act 295 Utility Energy Optimization Programs, November 30, 2009, p 18, available at https://www.michigan.gov/-/media/Project/Websites/mpsc/regulatory/reports/pa295-ewr/2009-2010_Projected_Energy_Optimization_Programs.pdf?rev=b3778e55c1554bc2a9831dbe21ae2cd7.

[32] MPSC Report on the Implementation of Public Act 295 Utility Energy Optimization Programs, November 30, 2010, revised January 2011, available at https://www.michigan.gov/-/media/Project/Websites/mpsc/regulatory/reports/pa295-ewr/2010_Energy_Optimization_Report.pdf?rev=ad32f2a4538c4c6abd77a764f02241d4 (indicating that the draft rules needed revision, resubmission, and a second round of public comment).

[33] MCL 460.1191, as amended by 2023 PA 235.

[34] Case No. U-15800, Order, December 4, 2008, pp 21-22 (referencing then-current MISO tariff).

[35] Ex D, Case No. U-21662, PFD, February 28, 2025, p 68.

> because of the wide disparity between MISO critical hours for intermittent generation and the current definition adopted in the Commission's temporary order.

The PFD recommended that the definition should be revised in a workgroup so that other utilities could provide input.[36] The PFD recommended that the Commission add the topic of revising the "peak demand time" definition to the workgroup that the PFD had previously recommended the Commission convene regarding the transfer price – which has been completed.[37]

The settlement in Case No. U-21662 provided:

> The Parties respectfully recommend that the Commission convene a work group to revise the definition of on-peak hours for determination of incentive renewable energy credits ("incentive RECs"). If the Commission accepts these recommendations, the parties also recommend that the Commission direct the work group to revise the definition to reflect times when non-wind renewable resources have capacity value and that it commence by June 7, 2025 and issue a final report to the Commission by September 1, 2025.[38]

Douglas Jester's attached presentation on incentive RECs explains that MISO's PY 2025-2026 wind and solar accreditation report bases solar accreditation on the hours ending 15, 16, and 17 Eastern Standard Time from March through November and the hours ending 8, 9, 19, and 20 EST from December through February.[39] The Commission should update the definition of peak demand time for incentive RECs to correspond with these hours. MEC incorporates all of the findings and recommendations in the presentation by reference into these comments.

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[36] *Id.*

[37] *Id.*

[38] Case No. U-21662, Order Approving Settlement Agreement, Ex A, paragraph 14.a.ii (emphasis added).

[39] Ex C, Douglas Jester, Renewable Energy Plan Incentive RECs Revisited.

Respectfully submitted,

TROPOSPHERE LEGAL, PLC
Counsel for MEC

Date: June 20, 2025

By: _____

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Transfer Price Symposium

May 30, 2012

MICHIGAN PUBLIC SERVICE COMMISSION

Why Is a Transfer Price Required?

- P.A. 295 of 2008 has a cap on the overall cost of meeting the renewable energy standard
- The cost cap requires the separation of the **additional cost** of renewable energy from normal utility expenses
- The cost of obtaining renewable energy is in many cases bundled with the total cost of energy from a given source

Commission Responsibility

- Determine the additional cost of renewable energy to enforce the statutory cap
- This done by transferring energy costs to the PSCR for recovery
- The commission shall annually establish a price per megawatt hour
- Shall be considered a booked cost of purchased and net interchanged power transactions under section 6j of 1939 PA 3

In setting the price per megawatt hour the commission shall

- Consider factors including, **but not limited to**
- Projected capacity costs
- Projected energy costs
- Projected maintenance and operating costs
- Information filed under section 6j of 1939 PA 3
- Information from wholesale markets, including, **but not limited to**, locational marginal pricing

Michigan Public Service Commission

Transfer Price Symposium

May 30, 2012

Jesse Harlow

Engineer, Renewable Energy Section

Michigan Public Service Commission

harlowj@michigan.gov 517-241-8793

Any views expressed are my own and not necessarily that of the Michigan Public Service Commission

MICHIGAN PUBLIC SERVICE COMMISSION

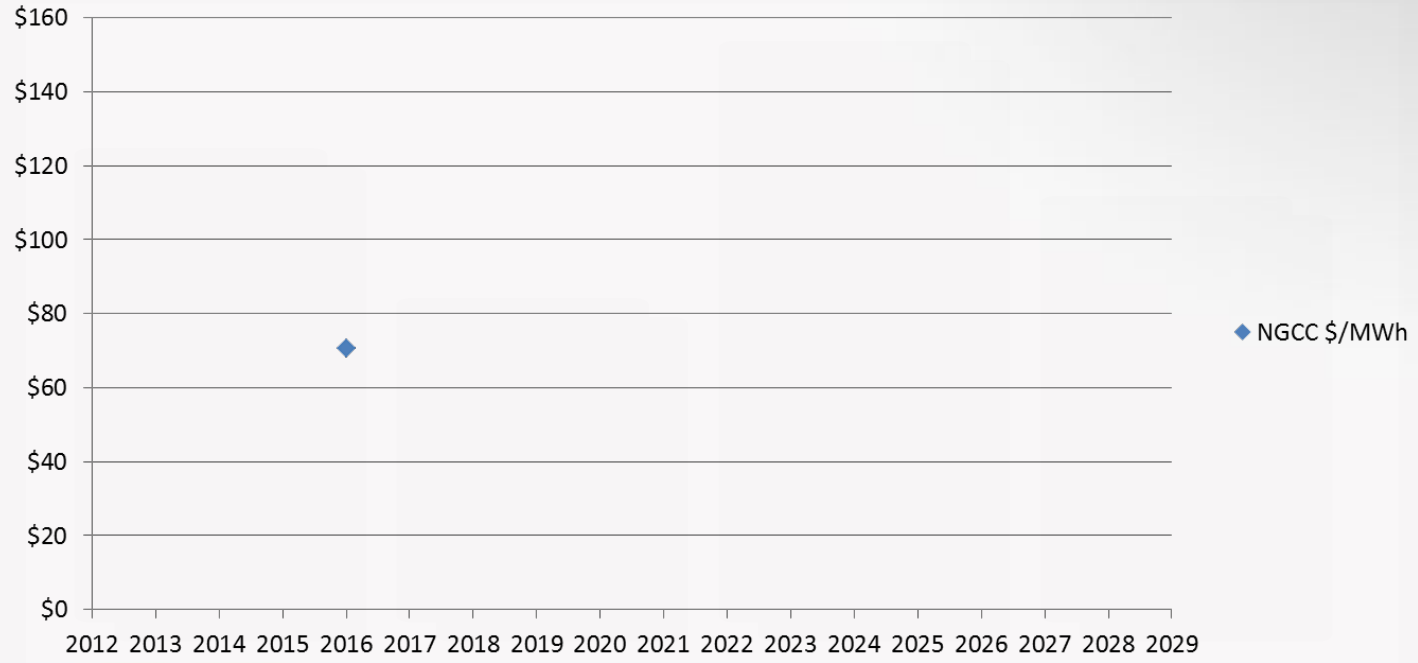
- Transfer Price Schedules should be a proxy for the cost to the provider of a similar long term "non-renewable" power purchase agreement
- These PPAs will most likely be modeled based on Natural Gas Combined Cycle plants

Methodology For Step One: Starting Point

- Use Natural Gas Combined Cycle (NGCC) plant $/MWh
  - Accounts for inflated capital costs over a four year construction phase
  - Includes AFUDC over the four years
  - On-line in 2016
  - Assumes relatively stable natural gas prices through plan period with growth on par with inflation

Starting Point

- 2016 On-line date
- $70.52/MWh



MICHIGAN PUBLIC SERVICE COMMISSION

Starting Point: Reasoning

- Natural gas should continue to set the on-peak LMP margin and start to set off-peak with greater NGCC utilization
- Pending EPA rules would favor NGCC compared to other generation and would require the retirement of less efficient plants
- NGCC has relatively quick ramp rates, good utilization factors and load following characteristics

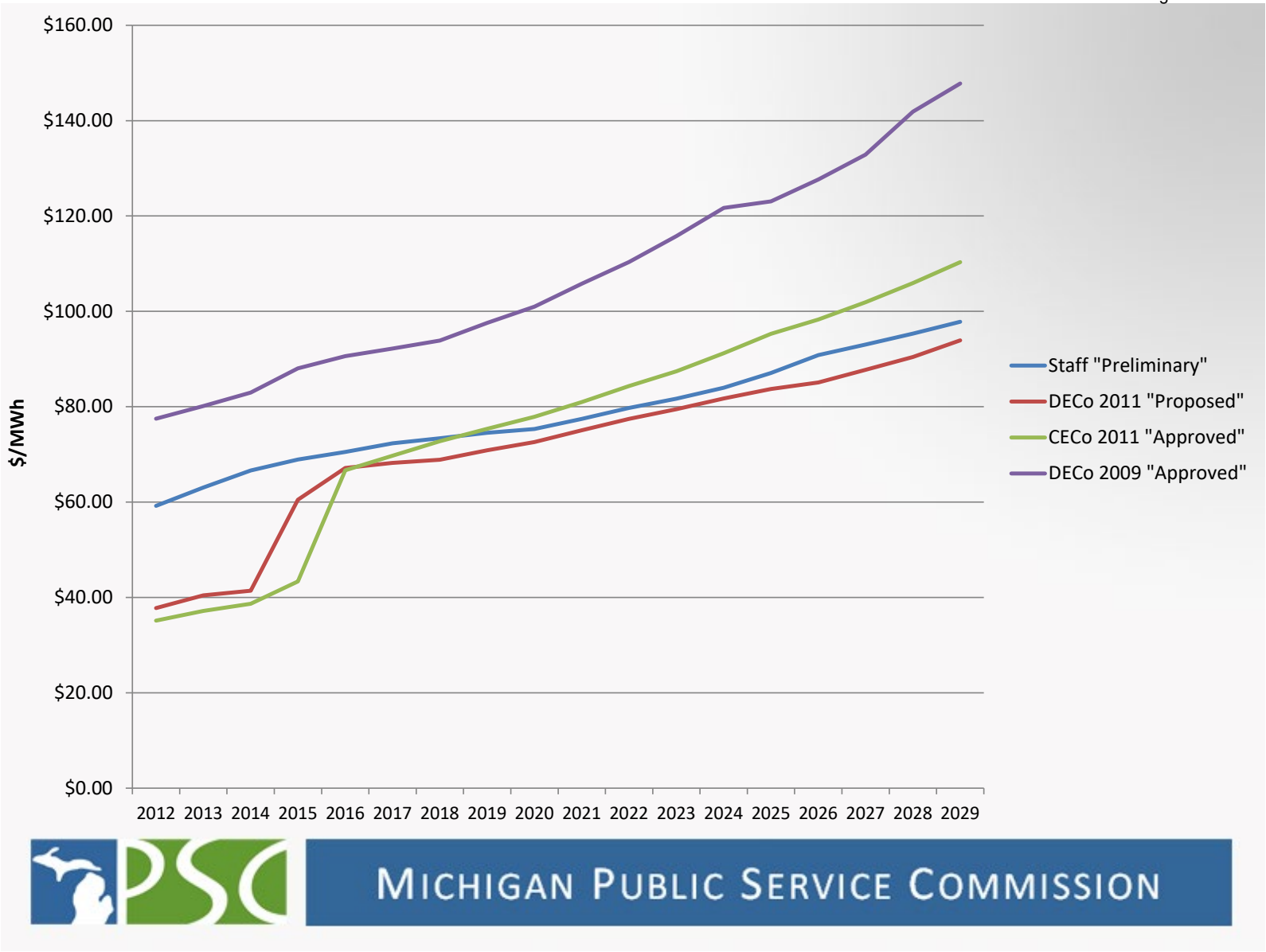
Methodology for Step Two: Growth Rate

- Utilize indices from a nationally recognized provider of economic forecasting data.
- Accounts for inflation
- Indices utilized:
  - Iron and Steel Prices
  - Concrete Prices
  - Turbine Prices
  - Natural Gas Prices

Growth Rate:

Reasoning

- The indices included have a direct impact on plant construction cost and future energy prices


$160.00
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
$/MWh
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029
Staff "Preliminary"
DECo 2011 "Proposed"
CECo 2011 "Approved"
DECo 2009 "Approved"
MICHIGAN PUBLIC SERVICE COMMISSION

	Staff "Preliminary"	DECo 2009 "Approved" U-15806	DECo 2011 "Proposed" U-16582	CECo 2011 U-16581
2012	$59.21	$77.49	$37.77	$35.14
2013	$63.05	$80.12	$40.45	$37.18
2014	$66.61	$82.97	$41.42	$38.69
2015	$68.92	$88.05	$60.48	$43.35
2016	$70.52	$90.61	$67.15	$66.66
2017	$72.34	$92.18	$68.21	$69.70
2018	$73.36	$93.86	$68.89	$72.77
2019	$74.56	$97.57	$70.86	$75.38
2020	$75.31	$100.97	$72.60	$77.90
2021	$77.46	$105.78	$75.05	$80.96
2022	$79.75	$110.33	$77.45	$84.34
2023	$81.69	$115.76	$79.48	$87.43
2024	$83.97	$121.69	$81.71	$91.24
2025	$87.10	$123.05	$83.71	$95.30
2026	$90.82	$127.66	$85.10	$98.29
2027	$93.02	$132.88	$87.75	$101.89
2028	$95.33	$141.88	$90.44	$105.93
2029	$97.82	$147.79	$93.92	$110.32

Staff Transfer Price Filing Logistics

- 2012-2029 Transfer Price Schedule and supporting data to be filed in RE Recon
- Starting in 2013 updated Transfer Price Schedules and supporting data filed in Docket No. U-15800 and RE Recon
  - Filed annually on or before April 1 to give providers ample time to prepare RE Recon

Renewable Energy Plan Transfer Prices After 2023 PA 2035

Douglas Jester, Managing Partner
5 Lakes Energy
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5lakes energy
www.5lakesenergy.com

In 2023, Michigan adopted Updated Renewable and New Clean Energy Standards

- PA 235 establishes the following standards for each electricity provider, including regulated investor-owned utilities, municipal utilities, cooperative utilities and alternative energy suppliers:
  - Renewable energy must be 15% of sales each year through 2029
  - Renewable energy must be 50% of sales each year 2030 through 2034
  - Renewable energy must be 60% of sales each year 2035 and thereafter
  - Clean energy must be 80% of sales each year 2035 through 2039
  - Clean energy must be 100% of sales each year 2040 and thereafter.
  - I&M and Wolverine have carve-out provisions because current or contracted nuclear generation exceeds 40% of sales, so their renewables only need to cover the balance of their sales.
- These standards do not prevent generation in Michigan that is not renewable or not clean.

In 2023, Michigan adopted Updated Renewable and New Clean Energy Standards

- Renewable energy consists of wind, solar, hydropower, and certain categories of biomass or biogas-fueled electricity generation.
  - Can be anywhere in the customer's RTO
  - Renewable energy credits (RECs) can be separated from power and transferred for compliance and have a shelf-life of 5 years
  - Only 5% of compliance can be stand-alone out-of-state RECs, but unlimited RECs can be out-of-state RECs bundled with capacity credits used in meeting resource adequacy standards
- Clean energy consists of non-emitting sources (wind, solar, hydropower, nuclear) or gas-fueled generation with carbon capture and storage that is 90% effective in reducing emissions from the gas plant.

Michigan Utilities Have No Need for New Gas Plants without CCS

Assume announced retirements and conversions and current capacity factors for other existing plants:

	Annual MWh			
	2024	2030	2035	2040
Sales (2% AGR)	98,831	111,300	122,884	135,674
Required Renewables	14,825	55,650	73,730	81,404
Required Clean	-	-	98,307	135,674
Existing Renewables	15,416	15,416	15,416	15,416
Incremental Renewables Needed	(591)	40,234	58,314	65,988
Existing Clean	39,667	39,667	39,667	39,667
Incremental Clean Needed inc Renewables	(39,667)	(39,667)	58,640	96,007
Incremental Clean Needed Not Necessarily Renewable	(39,076)	(79,901)	326	30,019
Losses (can be not-Clean)	7,906	8,904	9,831	10,854
Room for non-Export not-Clean	91,913	64,554	34,407	10,854
Continuing Gas	56,039	56,039	56,039	56,039
Continuing Other Fossil Generation	28,186	8,500	2,000	2,000
Existing Plants Excess Not-Clean	(7,688)	(15)	23,632	47,185

What new resource is avoided by new renewables?

- Other new renewables?
- New nuclear?
- New gas with CCS?

What is the appropriate basis for the transfer price?

- If a utility will only add renewables, then the cost of renewables is the transfer price and there is no incremental cost of compliance
- Gas with CCS is currently available and apparently less costly than new nuclear
- If a utility will add something besides renewables, cost of gas generation with CCS should be the transfer price

What is the cost of gas with CCS?

- Utilities can still use combustion turbines without CCS as a rarely-used capacity resource, so net CONE based on CT is the avoided cost of capacity
- EPA calculated the cost of CCS for a combined cycle plant as part of 111(b) rule-making
  - That cost, plus inflation since 2019, is $22.66 per MWh. This amount should be added to the energy portion of the transfer price computed for a CC in Staff's usual method.

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Renewable Energy Plan Incentive RECs Revisited

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5lakes energy
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In 2023, Michigan Adopted Updated Renewable and New Clean Energy Standards

- PA 235 establishes the following standards for each electricity provider, including regulated investor-owned utilities, municipal utilities, cooperative utilities and alternative energy suppliers:
  - Renewable energy must be 15% of sales each year through 2029
  - Renewable energy must be 50% of sales each year 2030 through 2034
  - Renewable energy must be 60% of sales each year 2035 and thereafter
  - Clean energy must be 80% of sales each year 2035 through 2039
  - Clean energy must be 100% of sales each year 2040 and thereafter.
  - I&M and Wolverine have carve-out provisions because current or contracted nuclear generation exceeds 40% of sales, so their renewables only need to cover the balance of their sales.
- These standards do not prevent generation in Michigan that is not renewable or not clean.

In 2023, Michigan Adopted Updated Renewable and New Clean Energy Standards

- Renewable energy consists of wind, solar, hydropower, and certain categories of biomass or biogas-fueled electricity generation.
  - Can be anywhere in the customer's RTO
  - Renewable energy credits (RECs) can be separated from power and transferred for compliance and have a shelf-life of 5 years
  - Only 5% of compliance can be stand-alone out-of-state RECs, but unlimited RECs can be out-of-state RECs bundled with capacity credits used in meeting resource adequacy standards
- Clean energy consists of non-emitting sources (wind, solar, hydropower, nuclear) or gas-fueled generation with carbon capture and storage that is 90% effective in reducing emissions from the gas plant.

2023 PA 235 Retained Incentive RECs for Compliance with the RES

- 2 RECs per MWh solar from a system approved before April 20, 2017
- 1/5 RECs per MWh from renewable energy other than wind at peak demand times determined by the commission.
- 1/5 RECs per MWh generated during off-peak hours, stored, and used during peak hours.
- 1/10 RECs per MWh generated during 1st 3 years operation if constructed using equipment made in Michigan.
- 1/10 RECs per MWh generated during 1st 3 years operation if constructed using Michigan workforce.

2023 PA 235 Retained Incentive RECs for Compliance with the RES

- MPSC adopted **temporary** guidance for incentive RECs in 2008 Order in Case No. U-15800
- In the 2008 Order, peak demand time was defined as: the period of time between 0600 hours EST through 2200 hours EST, Monday through Friday except holidays.
- MPSC should reconsider this definition of peak demand time, for both the non-wind peak demand incentive and the storage incentive

Peak Demand Time Incentive RECs Should Reflect Grid Value

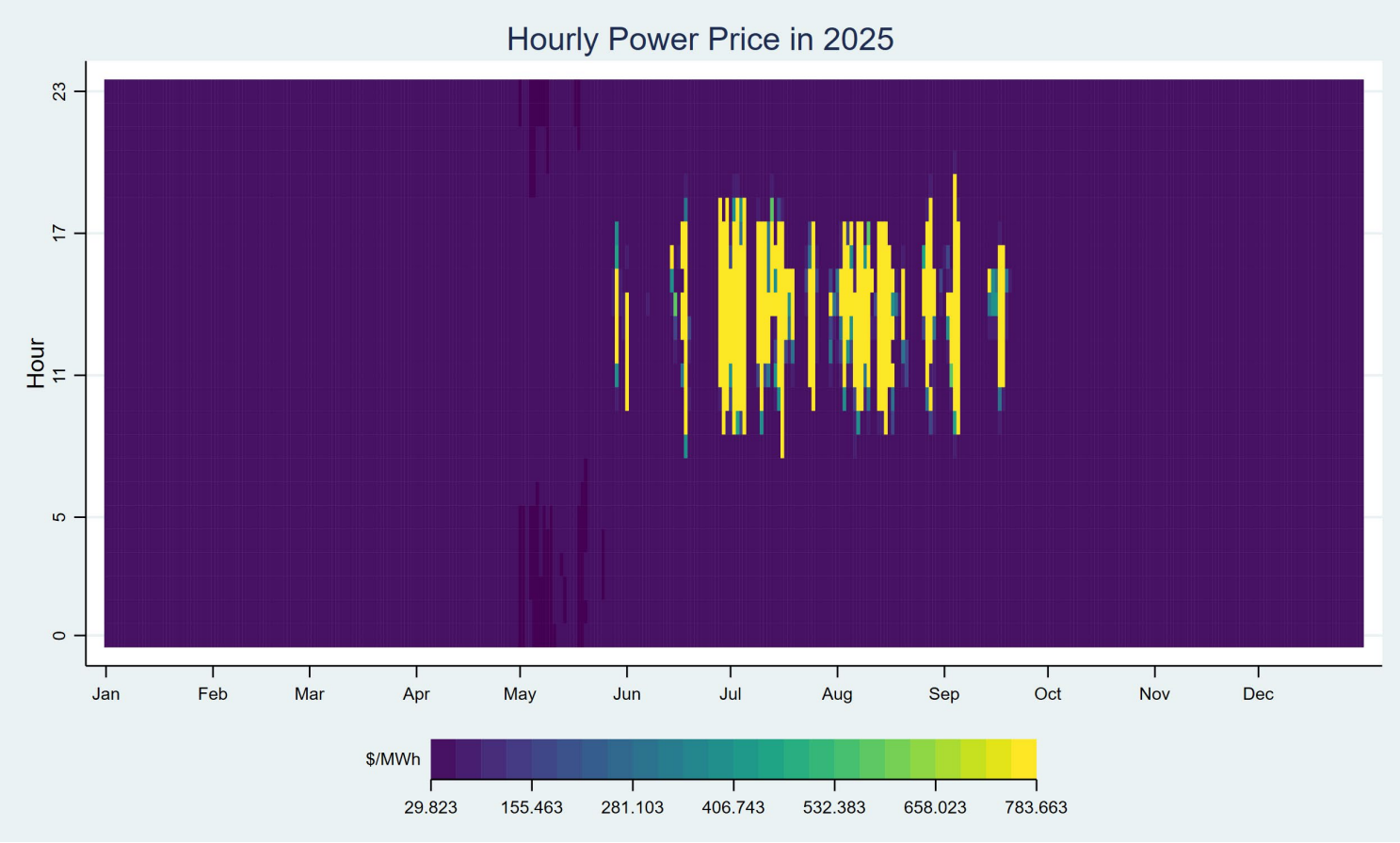
Grid value of generation is currently measured by locational marginal price of energy and by accredited capacity, and no other metrics. Avoided transmission costs would be an appropriate value, but front-of-meter generation does not reduce transmission charges.

Locational Marginal Price will quickly evolve away from solar

The following LMP heat maps are 5 Lakes Energy modeling results, assuming renewable build out approximately matching filed utility renewable energy plans and non-renewable resources from filed utility IRPs, and assuming EIA AEO gas prices.

Details of these results are disputable. Qualitative features are virtually certain.

Daytime locational marginal prices will be suppressed by planned solar development. Incentive RECs are not warranted for all daytime renewable generation from non-wind resources


Hourly Power Price in 2025
Hour
0
5
11
17
23
Jan
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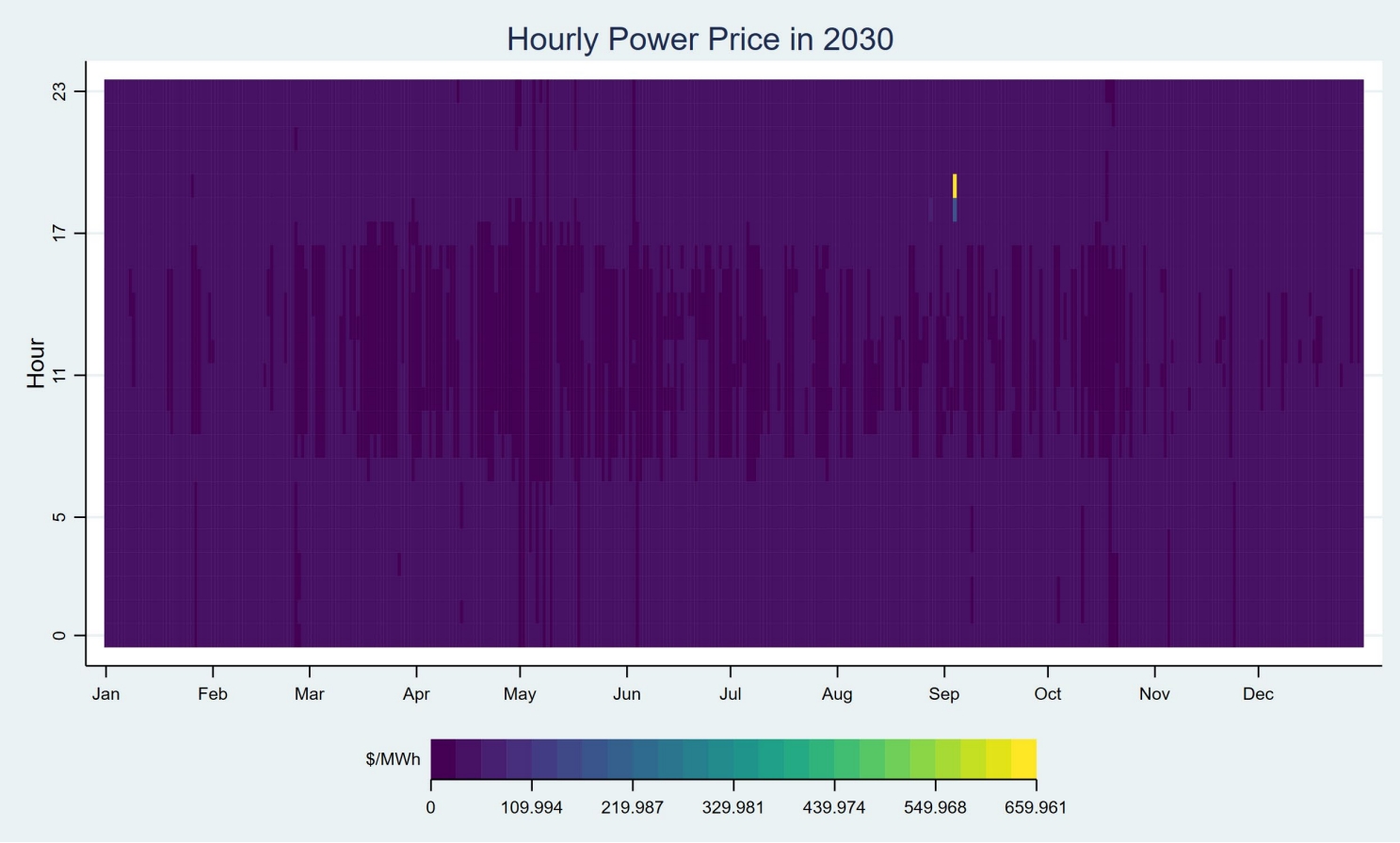
Oct
Nov
Dec
$/MWh
29.823
155.463
281.103
406.743
532.383
658.023
783.663


Hourly Power Price in 2030
Hour
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11
17
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Jan
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Nov
Dec
$/MWh
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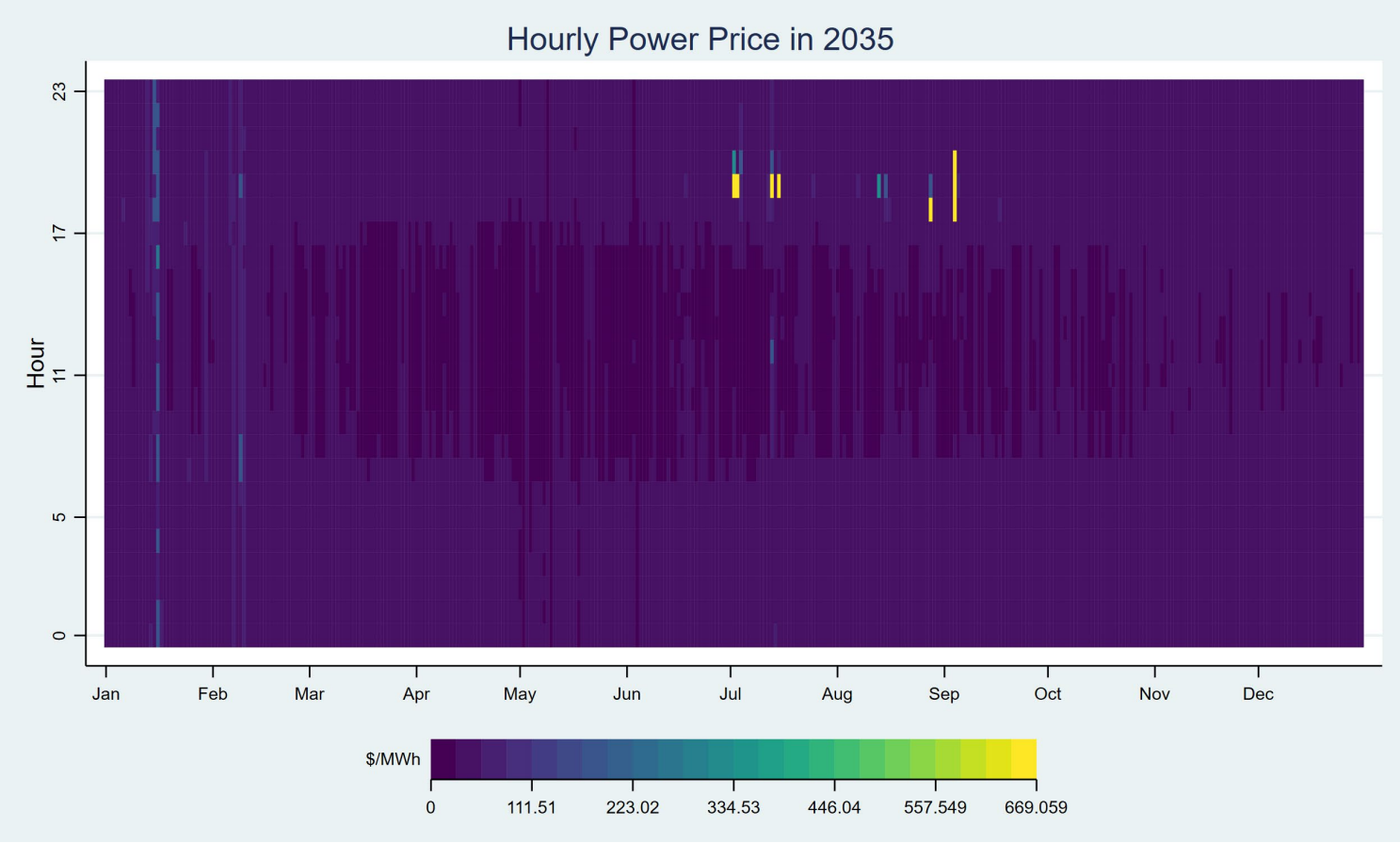
219.987
329.981
439.974
549.968
659.961


Hourly Power Price in 2035
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Oct
Nov
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$/MWh
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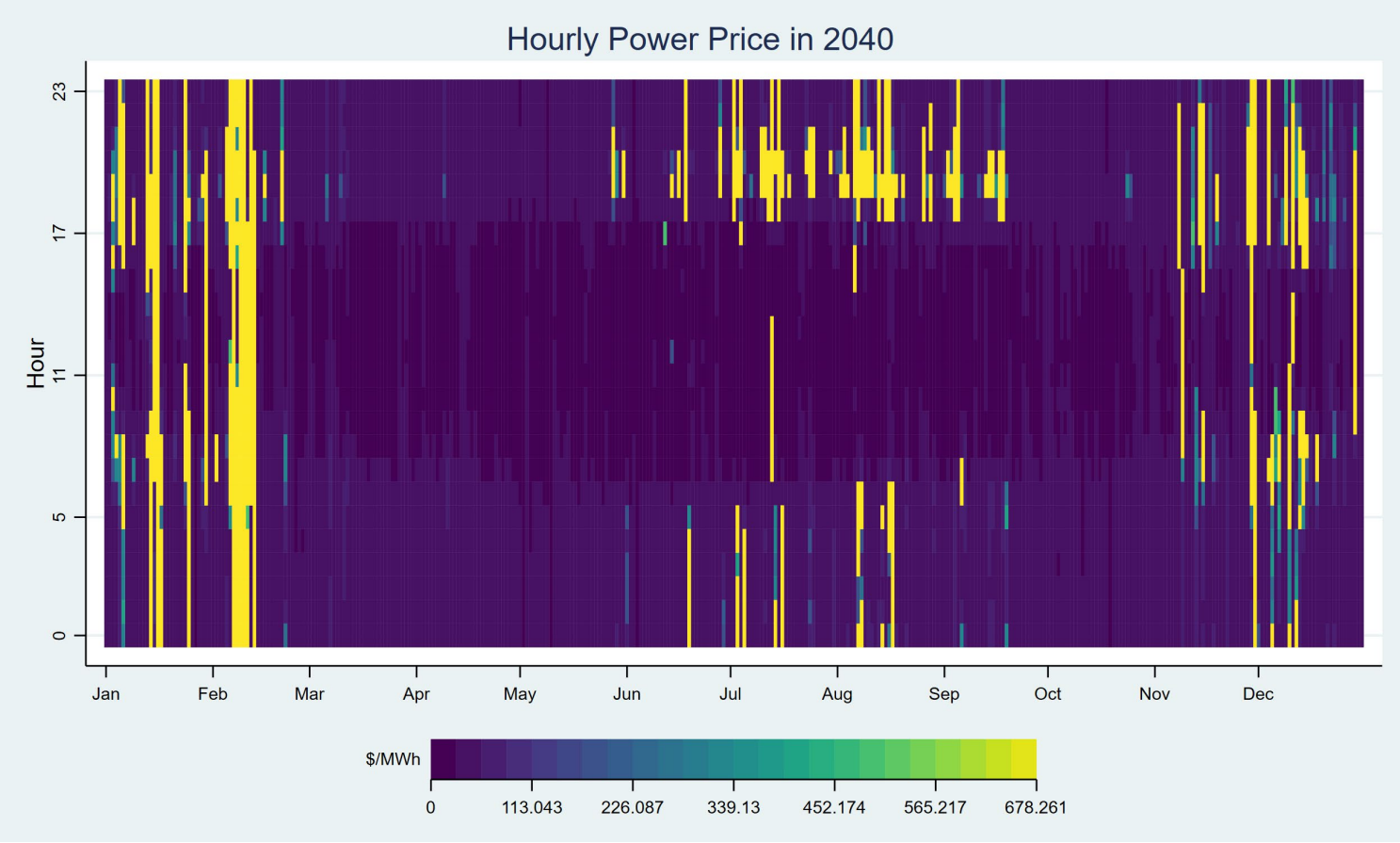
111.51
223.02
334.53
446.04
557.549
669.059


Hourly Power Price in 2040
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5
11
17
23
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
$/MWh
0
113.043
226.087
339.13
452.174
565.217
678.261

Capacity Accreditation has already changed

MISO has changed capacity accreditation to a seasonal construct with direct loss of load methods of accreditation.

MISO's PY 2025-2026 wind and solar accreditation report bases solar accreditation on the hours ending 15, 16, and 17 Eastern **Standard** Time from March through November and the hours ending 8, 9, 19, and 20 EST from December through February.

Presumably, the accreditation of hydropower, biomass, and biogas will be based on approximately the same times.

Capacity Accreditation has already changed

Those hours were chosen based on the 8 hours of MISO peak loads by season in 2022 through 2024 (all of which were on weekdays).

	Count of Hours in EST of MISO Seasonal Peak Demand 2022-2024										
	HE 7	**HE 8**	**HE 9**	**HE 13**	**HE 14**	**HE 15**	**HE 16**	**HE 17**	**HE 18**	**HE 19**	**HE 20**
January		7	3				1			5	
February		3	1								
March	2										
April											
May						2	11	8	1		
June						1	2				
July						1	10	1			
August						2	6	1			
September				1	1	2	17	1			
October							2				
November											
December			1						2		1
Annual	2	10	5	1	1	8	49	11	3	5	1

Proposed Storage Incentive RECs

Under the temporary 2008 Order in U-15800, storage incentive RECs were based on the assumption that all renewables generation at the time of charging/pumping were preferentially used for storage, so incentive RECs were based on the lesser of renewable generation and charging/pumping in each hour. Then, to the extent that discharge was within the peak demand period, incentive RECs were credited.

My testimony in DTE's 2024-5 AREP was that this is unreasonable and that because wind, solar, and hydropower are dispatched early in merit order, any pumping/charging is supplied by non-renewable resources unless renewables are being curtailed. DTE disagreed.

The settlement is that we both recommend to the Commission that renewable credits be placed into storage in proportion to the share of renewables in generation in the hour in which charging/pumping occurs.

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STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of DTE ELECTRIC COMPANY for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008 as amended.	))))))	Case No. U-21662

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on February 28, 2025.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before March 21, 2025, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before April 4, 2025.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

James M. Varchetti

Digitally signed by: James M. Varchetti
DN: CN = James M. Varchetti email = varchettij@michigan.gov C = US O = MOAHR OU = MOAHR - PSC
Date: 2025.02.28 12:08:46 -05'00'

James M. Varchetti
Administrative Law Judge

February 28, 2025
Lansing, Michigan

STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of DTE ELECTRIC COMPANY for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008 as amended.	))))))	Case No. U-21662

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On July 19, 2024, DTE Electric Company (the company) filed its application seeking approval of its amended renewable energy plan (REP), and related relief, pursuant to 2008 Public Act 295, as amended by 2023 PA 235, MCL 460.1001 *et seq*. The timing of the company's application for approval of its amended REP complied with the Commission's Order in Case No. U-21568, *In the matter, on the Commission's own motion, to implement the provisions of Sections 22 through 49 and related definitions of Public Act 235 of 2023*.[1]

At the September 11, 2024, prehearing conference held by the undersigned Administrative Law Judge, the company and the Commission Staff appeared, and

[1] See Case No. U-21568, February 8, 2024, Order, p 2 (directing DTE Electric Company to file its amended REP no later than July 19, 2024.).

intervention was granted to petitioning parties including the Association of Businesses Advocating Tariff Equity (ABATE), the Michigan Environmental Council and Sierra Club (collectively MEC-SC), the Great Lakes Renewable Energy Association (GLREA), and the Ecology Center, the Environmental Law and Policy Center, the Union of Concerned Scientists, and Vote Solar (collectively the Clean Energy Organizations or CEO). At the prehearing conference, a schedule for this matter was adopted.

Consistent with the established schedule, Staff and the intervening parties, excluding GLREA, filed testimony on October 31, 2024. In turn, on November 21, 2024, the company, Staff, and ABATE filed rebuttal testimony. On December 6, 2024, and December 9, 2024, evidentiary hearings were held at which legal counsel for MEC-SC cross-examined selected witnesses presented by the company and Staff.[2] At the hearings, the parties also bound into the record the pre-filed testimony of their witnesses and their associated exhibits as described *infra*.

On December 26, 2024, the company filed a petition requesting several corrections to the transcript of the cross-examination proceedings pursuant to Mich Admin Code, R 792.10415(5). No party filed any objections to the company's petition for corrections to the transcript, and on January 3, 2025, the company's petition was granted, and a ruling was entered on the docket to correct the transcript in accordance with the company's petition.

On January 10, 2025, all parties (excluding GLREA) filed their initial briefs, and on January 31, 2025, the parties, excluding GLREA and Staff, filed reply briefs.

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[2] On each day of the cross-examination hearings, a motion *pro hac vice* was granted allowing out-of-state attorneys to represent Sierra Club to allow them to cross-examine witnesses during the hearings.

II.

OVERVIEW OF THE RECORD

As discussed above, the parties presented evidence to be bound into the record at the evidentiary hearings held on December 6, 2024, and December 9, 2024. During the evidentiary hearings, the company entered the testimony of eight witnesses:

1. Kevin L. Bilyeu, Manager of Renewable Energy Strategy and Special Projects, (Direct and Rebuttal);
2. Carl Edward "Eddie" Smith, Manager of Product Development and Residential Marketing for Voluntary Renewables at DTE Electric (Direct and Rebuttal);
3. Patrick D. Kauffman, Accounting Expert for the company's Renewable Energy Group (Direct only);
4. Frank F. Kopinski, Principal Engineer in the Power Supply Systems & Modeling team within the company's Generation Optimization Department (Direct only);
5. Kirk M. Vangilder, Principal Financial Analyst for Revenue Requirements within the company's Regulatory Affairs organization (Direct only);
6. Sherri L. Wisniewski, Director of Tax Operations for the company (Direct only);
7. Nathan D. Bennett, Manager of Clean Energy & Acquisitions within the company (Direct only); and
8. Emily C. Meloche, Data Analyst in the company's Corporate Energy Forecasting team (Direct and Rebuttal).

Through these witnesses, the company entered Exhibits A-1 through A-35.[3]

[3] This is inclusive of Exhibit A-20.1, which was the company's only exhibit that was not delineated exclusively by a whole number.

Staff entered the direct and rebuttal testimony of one witness, Jesse J. Harlow, Manager of the Renewable Energy Section in the Commission's Energy Resources Division. Staff did not present any exhibits for admission into the record.

MEC-SC presented the direct testimony of three witnesses in its evidentiary presentation:

1. Douglas B. Jester, Managing Partner of 5 Lakes Energy;
2. Eli K. Gold, Senior Consultant with 5 Lakes Energy; and
3. Devi Glick, Senior Principal at Synapse Energy Economics.

Through these witnesses, MEC-SC entered Exhibits MEC-1 through MEC-12, MEC-14 through MEC-23, MEC-26, MEC-27, MEC-29 through MEC-41, and MEC-43 through MEC-45.

ABATE presented the direct and rebuttal testimony of one witness, Jessica A. York, a consultant in the field of public utility regulation and a principal of the firm Brubaker & Associates. ABATE entered Exhibits AB-1 through AB-7.

CEO entered the direct testimony of two witnesses:

1. William D. Kenworthy, the Regulatory Director of the Midwest for Vote Solar;
2. Michael B. Jacobs, a Senior Energy Analyst with the Union of Concerned Scientists.

Through these witnesses, CEO entered Exhibits CEO-1 through CEO-12.

The evidentiary record in this matter is contained in the testimony and exhibits described above that were bound into the record during the December 6, 2024, and December 9, 2024, evidentiary hearings. Pertinent aspects of the evidentiary record

necessary to resolve issues disputed by the parties are discussed individually in greater detail below.

III.

DISCUSSION

The company's application for approval of its amended REP addresses various topics needed for the company's amended REP to meet new requirements imposed by Public Act 235 of 2023 (PA 235), MCL 460.1001 *et seq*., which became effective in February of 2024. These topics include, but are not limited to: (1) how the company will address the new renewable portfolio standard (RPS) consistent with MCL 460.1028 and how the amended REP aligns with the company's 2022 Integrated Resource Plan (IRP) in Case No. U-21193; (2) calculations related to the company's Renewable Energy Credit (REC) portfolio under MCL 460.1028; (3) the bidding process to be used by the company under MCL 460.1028(6); (4) the expected incremental cost of compliance (ICOC) under MCL 460.1045; (5) considerations regarding the need for a volumetric recovery mechanism for recovery of the ICOC consistent with MCL 460.1022(2); and (6) reasons why the amended REP is both reasonable and prudent as well as consistent with the goals set forth in MCL 460.1001 such that it is fit for approval by the Commission. See MCL 460.1022(5) (setting forth criteria for approval of an amended REP).

Overall, Staff and the intervening parties generally support approval of the company's amended REP with certain exceptions or recommended changes.[4] For the

[4] See e.g. 2 Tr 25 (In which Staff witness Harlow expresses overall support for the amended REP with only certain exceptions); see also 2 Tr 136 (In which MEC-SC witness Jester opines that the company's amended REP appears to satisfy the standards of 2023 PA 235, but that certain elements of the plan are not the most reasonable options available).

sake of brevity, this PFD will not address the undisputed aspects of the company's amended REP and recommends that the Commission approve the aspects of the company's amended REP that have been reviewed but not disputed by Staff or other intervenors. This PFD will address the distinct aspects of the company's amended REP that are disputed by the parties.[5]

A. The Pine River Project and Cost Recovery through the PSCR Transfer Price

1. Testimony

Mr. Bennett testified that the company and partner organizations planned to pursue a grant from the Department of Energy (DOE) for the Pine River long duration energy storage (LDES) project that would hybridize the Pine River wind park (and future solar park) with a 1.4 MW battery, and later with second-life electric vehicle batteries.[6] He stated that in addition to Pine River, the company was considering its existing and near term-renewable facilities as potential candidates for co-located storage.[7]

Mr. Bennett asserted that Michigan's energy law does not explicitly state whether the costs of co-located storage can be recovered through the REP. However, he stated that MCL 460.1011(i) defines "renewable energy system" 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."[8] He further added that MCL

[5] In briefing MEC-SC presented an argument, unsupported by testimony, that the Commission should direct the company to reduce the projected costs of the amended REP if the Commission lowered the company's authorized return on equity in the company's then-pending rate case, i.e. Case No. U-21534. See MEC-SC, 74-78. This PFD considers this argument moot because the Commission did not alter the company's authorized return on equity in that case.
[6] 3 Tr 571.
[7] 3 Tr 576.
[8] 3 Tr 577-578 (quoting MCL 460.1011(i)).

460.1011(g) defines "renewable energy resource" to include wind and solar power.[9] Mr. Bennett stated that his interpretation of these statutes, as a non-attorney, was that co-located energy storage would qualify as a renewable energy system, thus allowing recovery through the REP. He added that, more specifically, the energy storage could be charged by the renewable energy facility by capturing otherwise curtailed or clipped energy, and that the storage could also otherwise "effectively charge from the renewable energy facility given that they are at the same point of interconnection."[10] Mr. Bennett also opined that recovering costs of co-located storage through the REP was appropriate because it would allow approval of co-located storage and renewables in a single filing and because in calculating the ICOC under MCL 460.1047, the Company may include "any additional electric provider costs determined by the commission to be necessarily incurred to ensure the quality and reliability of renewable energy used to meet the renewable energy standards."[11]

Mr. Bennett testified in detail about the company's proposal for recovering the cost of co-located energy storage resources through the transfer price mechanism:

> The Company proposes that LMP-based charging costs and discharging benefits for co-located storage would flow through the Power Supply Cost Recovery (PSCR) mechanism as purchases and sales of energy. The Company further proposes that the levelized cost of the revenue requirement for the fixed costs of the co-located storage resource be recovered through the REP transfer price mechanism.
>
> * * *
>
> The Company's preferred approach to establishing a transfer price for co-located energy storage would be to use a capacity-based transfer price rather than an energy-based transfer price like those used in the REP today. A capacity-based transfer price aligns with how the Company intends to contract for third party energy storage resources in the future (i.e., through

[9] 3 Tr 578 (citing MCL 460.1001(g)).
[10] 3 Tr 578.
[11] 3 Tr 578 (quoting MCL 460.1047).

> tolling agreements with prices established in $/kW-month). However, the language in MCL 460.1047(2)(b)(iv) specifies that the transfer price be established as a "price per megawatt hour".
>
> In order to align the cost of the co-located energy storage with the existing transfer price framework, the Company proposes that the fixed cost of the energy storage resource be levelized over the available energy (in megawatt hours) over the life of the project. The available energy is defined as the battery's maximum discharge capacity (in megawatts) multiplied by the number of hours that the battery is available. For a representative 100 MW battery with 95% availability over the course of a calendar year, the available energy would be equal to 100 MW multiplied by the 95% availability multiplied by the hours in the year.[12]

Mr. Bennett requested that the Commission approve the inclusion of costs for the Pine River LDES project conditional upon grant approval from the DOE and also approve the plan to co-locate energy storage with renewables and recover the fixed costs of the storage resource through the transfer price mechanism as proposed by the company.[13]

Mr. Harlow explained Staff's concerns about the company's proposal to recover the fixed costs of co-located storage resources through the transfer price mechanism using a calculation based on availability of the storage asset. He testified that Staff's concerns are two-fold: (1) storage is not listed as a renewable energy resource under MCL 460.1011(g), and historically only renewable energy resources are included in the transfer price; and (2) the transfer price mechanism has historically utilized actual energy output of a renewable resource on a MWh basis to calculate the transfer price.[14] Mr. Harlow asserted that the company's methodology—which assigns a transfer price based on the availability of a storage asset—would assign a transfer cost that disassociates actual production of the asset from the amount recovered through the transfer price

[12] 3 Tr 579-580.
[13] 3 Tr 581.
[14] 2 Tr 27.

mechanism.[15] He explained that the company's methodology would result in an expediated recovery of the storage asset when compared to a transfer price mechanism based on actual energy output because the availability of a storage asset is approximately 95%.[16]

Mr. Harlow stated that both he and company witness Bennett, as non-attorneys, appeared to agree that PA 235 does not specifically address whether a storage asset may be recovered in the transfer price.[17] But, he explained that PA 235 established a statewide energy storage target of 2,500 MW to be apportioned among electric providers, and the act provided that for approved, eligible storage contracts an electric provider is directed "to recover the costs of the contract in the electric provider's base rates."[18] Accordingly, Mr. Harlow submitted that "the most obvious solution" was that the fixed costs of co-located storage resources should be recovered in base rates, through a general rate case.

Mr. Harlow explained that Staff's preferred method for the recovery of company-owned storage assets "is to separate out the costs of storage assets and include these costs in base rate cases" because it is the "most obvious statutory solution with respect to the assets and avoids pitfalls associated with other methodologies."[19] He recommended that it be employed in this case and he rejected the notion that this would

[15] 2 Tr 27-28.
[16] 2 Tr 28.
[17] 2 Tr 28.
[18] 2 Tr 28 (quoting MCL 460.1101(4)).
[19] 2 Tr 29.

be administratively burdensome to utilities because "regulated utilities are well versed at separating and reporting costs."[20]

Mr. Harlow also stated that another feasible option, while not preferred by Staff, "would be to apply the fixed cost component of the transfer price to the availability of the storage asset, as this represents the proxy capacity costs and aligns better with the actual value and utilization of the storage asset."[21] He opined that this was a feasible option because, "[w]hile storage is not listed in the definition of a renewable energy resource in MCL 460.1011(g), MCL 460.1039(2)(c) does allow for the creation of 1/5 Michigan incentive renewable energy credits for renewable energy electricity generated off-peak hours (hours 23-6 M-F excluding holidays) and stored using an energy storage system."[22]

However, Mr. Harlow envisioned that there may be a scenario in which storage resources could qualify for the PSCR transfer price mechanism. He explained:

> To put it simply, Staff recognizes that Company-owned or purchased energy resources fall squarely within the transfer price. Storage of those resources, however, does not necessarily squarely fit into the transfer price mechanism recovery, depending on the facts. Staff can foresee, however, a future in which the Company, or another utility, enters into a power purchase agreement for a co-located renewable energy asset with storage, as a single facility, similar to an energy system, referred to in the Act. In this situation, it makes sense that the combined output of this facility should be eligible for the transfer price cost mechanism recovery if the output of the facility was metered through a single meter and billed to Company as a single monthly bill, as the costs would relate solely to a renewable resource and be appropriately handled through a PSCR case.[23]

Mr. Harlow testified that there would likely be cost savings associated with developing co-located storage and renewable generation when compared to developing such assets

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[20] 2 Tr 29.
[21] 2 Tr 30.
[22] 2 Tr 30.
[23] 2 Tr 29.

separately.[24] However, he opined that due to the variability of renewable resources, co-location could result in an inefficient use of the storage asset such that Staff would recommend installing co-located storage in a manner that allows it to optimize charging using both the interconnected renewable asset and the grid itself.[25]

Finally, Mr. Harlow recommended that the Commission define co-located storage using MISO definitions if it chooses to approve cost recovery for co-located storage to distinguish co-located storage from stand-alone storage. He explained that for projects developed together, co-located storage would be defined as sharing the same MISO point of interconnection, while for projects in which storage was later added, the storage must be eligible to take advantage of the MISO surplus interconnection process in order to be considered co-located.[26]

In rebuttal, Mr. Bennett opined that there was additional statutory language in MCL 460.1011(g) that Mr. Harlow did not consider. He contended that MCL 460.1011(g) did not specifically exclude storage energy from the definition of “renewable energy resource” and instead specifically excluded certain other energy resources such as petroleum, coal, and natural gas among others.[27] He added that MCL 460.1011(j) did not specifically exclude energy storage aside from hydroelectric pumped storage.[28] Further, Mr. Bennett contended that there are other statutory references to co-located storage being a renewable energy resource because a different act, 2023 PA 233, defines “solar energy facility” and “wind energy facility” to include “energy storage facilities” at MCL 460.1221(w)

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[24] 2 Tr 31.
[25] 2 Tr 31.
[26] 2 Tr 32.
[27] 3 Tr 584.
[28] 3 Tr 585-585.

and (x).[29] Mr. Bennett asserted that as a non-attorney, his interpretation of these statutory references was that Michigan's energy laws did not prohibit cost recovery of co-located energy storage through the REP because it was not specifically excluded from MCL 460.1011(g) or (j), and it was clear from PA 233, passed at the same time as PA 235, that the legislature intended co-located storage to be included in wind and solar facilities.[30]

Mr. Bennett critiqued Staff's preferred method for cost recovery, i.e. separating the cost of storage and recovering it in base rates, as a two-step approval process whereby the renewable resource would be approved in a REP and the storage portion would be approved through a rate case.[31] He asserted that separation and allocation of costs was only one issue with Staff's preferred approach, and he opined that "[t]he larger issue is that a two-step approval process unnecessarily introduces significant uncertainty into the project development process and will pose challenges for project design, permitting, and procurement."[32] He stated that because of this uncertainty, the company "will be unable to separate and allocate the appropriate costs as Witness Harlow suggests since those costs will necessarily depend on whether the project will be a standalone solar project, a standalone storage project, or a solar + storage project."[33] He explained that under a two-step approval process the scope of the project would not be known until the second step in the approval process such that it would not be possible to properly allocate costs for approval and recovery under step one until the outcome of step two is known.[34]

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[29] 3 Tr 585.
[30] 3 Tr 585.
[31] 3 Tr 586.
[32] 3 Tr 586.
[33] 3 Tr 586.
[34] 3 Tr 586.

Mr. Bennett asserted that a two-step approval process would require separate designs and permitting to accommodate the range of approval outcomes, which could increase the cost of designing and permitting a project. [35] He asserted that the company could conceive of options[36] to work within a two-step framework proposed by Staff, but they would involve increased costs, longer times to deliver projects, or both.[37]

Mr. Bennett also addressed Staff's alternative cost-recovery proposal, i.e. applying the fixed cost component of the transfer price to the availability of the storage asset, by stating that it was "reasonable" although the company maintained its original proposal.[38]

Finally, Mr. Bennett stated that he agreed, in part, with Staff's proposed definition of co-located storage. He specified that co-located storage should be defined as sharing the same point of interconnection.[39] However, he asserted that Mr. Harlow's definition "is not clear as 'co-located' is not a defined term in the MISO tariff."[40] He also contended that Staff's proposal to tie the cost recovery construct to the process by which the resource is interconnected is unduly restrictive and could affect storage resources that could otherwise be considered a part of the renewable energy system.[41] He specified that there are multiple processes for adding storage to an existing interconnection in addition to the MISO surplus process including amended interconnections, generator retirement and

[35] 3 Tr 588.
[36] These options included moving forward with the solar portion of a design as if it was a standalone project and then modifying the design if storage was approved, leading to costs associated with redesigning the project. 3 Tr 588. The other option explained by Mr. Bennett was to move forward with the solar and storage portions of a project upon approval of the solar portion and risk disallowance of the storage portion if it was not approved later. 3 Tr 588-589.
[37] 3 Tr 588.
[38] 3 Tr 590.
[39] 3 Tr 590.
[40] 3 Tr 590.
[41] 3 Tr 590.

replacement, and distribution interconnection.[42] Mr. Bennett asserted that it was unclear why Staff's proposed definition would seek to exclude such projects, and he opined that the Commission should simply define co-located resources as those sharing the same point of interconnection and should reject the other facet of Staff's proposed definition.[43]

2. Briefing

The company's brief closely tracks and repeats the direct and rebuttal testimony of Mr. Bennett seeking approval of the Pine River project and the company's cost recovery through the transfer price mechanism.[44] The company argues that co-located energy storage falls under the definition of a "renewable energy system" in MCL 460.1011(i), and that storage could be considered a renewable energy resource under MCL 460.1011(g).[45] The company argues that PA 233—passed contemporaneously with PA 235—defines storage facilities to be part of a solar energy facility or a wind energy facility, and that these two acts should be read together as a whole and be harmonized in the context of REP proceedings.[46] As a supplementary argument, the company contends that cost-recovery of co-located storage is permissible under MCL 460.1047 because, when calculating the ICOC, the company may include additional costs determined by the Commission to be necessarily incurred to ensure the quality and reliability of renewable energy to be used to meet the RES.[47] The company remains opposed to Staff's proposed

[42] 3 Tr 591.
[43] 3 Tr 592.
[44] See generally DTE, 51-63.
[45] DTE, 55-56.
[46] DTE, 56-57.
[47] DTE, 57.

approach, which the company contends necessitates a two-step process for cost recovery that decreases certainty and complicates cost recovery.[48]

Staff supports the Pine River LDES project with the recommendation that the Commission should approve the project as a pilot following the same requirements as a pilot project.[49] Staff reiterates its concern that storage is not a renewable energy resource and thus there could be no direct MWh basis for calculating an associated transfer price for cost recovery.[50] Staff says its proposed alternative cost-recovery method is based on the recognition that in the future co-located renewable energy and storage as a single facility could qualify for recovery in the PSCR.[51] This seems to suggest that Staff does not believe that such cost recovery should be available for the Pine River LDES. Generally, Staff's brief repeats and directly quotes Mr. Harlow's direct testimony relating to this issue.[52]

In reply, the company asserts that harmonizing the definitions in PA 233 and PA 235 and understanding that MCL 460.1011(g) is non-exhaustive resolves Staff's primary concern that co-located storage is not a renewable energy resource.[53] Further, the company urges the Commission not to defer a decision on the company's requested cost recovery mechanism for co-located storage, as Staff seems to suggest, stating:

> This Amended REP proceeding is the appropriate forum for deciding the Company's requested relief and the contours of Act 235. DTE Electric intends to solicit renewables, energy storage or co-located projects in future RFPs. In this Amended REP proceeding, the Company needs the Commission's confirmation on cost recovery of co-located storage to

[48] See DTE, 58-60.
[49] Staff, 9.
[50] Staff, 10.
[51] Staff, 11-12.
[52] See Staff, 9-13.
[53] DTE Reply, 35.

navigate the competitive procurement process and secure the resources needed to comply with Act 235. Without such confirmation in this Amended REP proceeding, the lack of clarity on cost recovery could hinder resource procurement.[54]

3. Conclusion and Recommendation

a. Pine River LDES Project

This PFD agrees with Staff's recommendation to approve the Pine River LDES and recommends approval of $5,114,175[55] for the Pine River project, contingent upon DOE grant approval and following all the requirements for pilot projects outlined in Case No. U-20645.

b. Cost Recovery of Co-located Energy Storage

This PFD agrees with Staff that energy storage costs, including co-located energy storage costs, should be recovered in base rates. As Staff points out, PA 235 speaks directly to the issue of cost recovery of energy storage at MCL 460.1101(4) and directs cost recovery in base rates for eligible energy storage contracts.[56] The statute uses the word "shall" which indicates a mandatory directive.[57] The language of MCL 460.1101(4)

[54] DTE Reply, 37.
[55] See 3 Tr 573 (explaining the company's cost-share for the project).
[56] That provision states in pertinent part: "An electric provider whose rates are regulated by the commission *shall* submit to the commission for review and approval eligible energy storage contracts entered into to meet its share of the statewide storage target under [MCL 460.1101(1)]. If the commission approves an eligible energy storage contract, the commission *shall* authorize the electric provider to recover the costs of the contract in the electric provider's base rates." MCL 460.1101(4) (emphasis added). The statute also defines an "eligible energy storage contract" as "a contract to construct, acquire, or use the services of an eligible energy storage system." MCL 460.1101(9)(a). In turn, an eligible energy storage system is defined as "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." MCL 460.1101(9)(b).
[57] See *Fradco Inc v Dep't of Treasury*, 495 Mich 104, 114; 845 NW2d 81 (2014) (stating that the Legislature's use of the word "shall" in a statute generally indicates a mandatory and imperative directive); accord *People v Lockridge*, 498 Mich 358, 387; 870 NW2d 502 (2015).

is clear and unambiguous and reflects the Legislature's intent that energy storage costs should be recovered in base rates.[58]

Absent any specific statutory reference to co-located energy storage cost recovery, the directive at MCL 460.1101(4) to recover storage costs through base rates trumps the other arguments presented by the company that advocate the use of the PSCR transfer price mechanism to recover storage costs. The company's argument for PSCR transfer price cost recovery based upon practical difficulties and uncertainty associated with cost recovery in base rates may have cogency as a policy-based argument. Nevertheless, those concerns cannot overcome the Legislature's intent as expressed in the language of MCL 460.1101(4), and the company never directly addressed the cost recovery language in that statutory provision.

A "renewable energy system" is defined at MCL 460.1011(i),[59] and this PFD agrees with suggestions by the company and Staff that battery storage co-located with renewable energy generation could conceivably fall within the definition of a renewable energy system.[60] Nevertheless, cost recovery of such a co-located energy storage resource should still be through base rates as directed by MCL 460.1101(4). That provision directly and specifically addresses energy storage cost recovery, while recovery through the transfer price, MCL 460.1047(2)(b)(iv), would only do so indirectly by implication.[61]

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[58] See *City of Grand Rapids v Brookstone Cap, LLC*, 334 Mich App 452, 459; 965 NW2d 232 (2020) ("When courts interpret statutes, they must first look to the specific statutory language to determine the intent of the Legislature, and if the language is clear and unambiguous, the plain meaning of the statute reflects the legislative intent and judicial construction is not permitted.").

[59] That provision states in pertinent part that: "'renewable energy system' means a facility, electricity generation system, or set of electricity generation systems that use 1 or more renewable energy resources to generate electricity or steam." MCL 460.1011(i).

[60] See DTE, 55; Staff, 12.

[61] *See Milne v Robinson,* 513 Mich 1, 12–15; 6 NW3d 40 (2024) (discussing generally the rationale behind the maxim that a more specific statutory provision governs over a more general one).

Additionally, because MCL 460.1101(4) expresses the Legislature's intent on energy storage cost recovery there is also no need to harmonize definitions in PA 233 and PA 235 as argued by the company. Further, this PFD finds that MCL 460.1221(w) and (x) in PA 233 are not in conflict or tension with MCL 460.1011(g) in PA 235, as the company suggests.[62] PA 235 sets goals for energy storage capacity and renewable energy generation and refers to "renewable energy *systems*"[63] and "energy storage *systems*"[64] separately and distinctly. On the other hand, PA 233 provides for the siting of an "energy *facility*" defined as "an energy storage *facility*, solar energy *facility*, or wind energy *facility*."[65] Further, the definitions in MCL 460.1221(w) and (x) include a long list of equipment and facilities that may be included in a solar or wind energy facility, such as substations, interconnection or switching facilities, circuit breakers and transformers, and *"energy storage facilities*." That a solar or wind energy facility may also include an energy storage facility does not lead to the conclusion that a co-located energy storage facility *is* a solar or wind energy facility under PA 233 or that co-located storage is necessarily a renewable energy resource under PA 235.

This PFD disagrees with the company's argument that co-located energy storage, even though not expressly listed in MCL 460.1011(g), is a "renewable energy resource" and is therefore eligible for cost recovery through the transfer price mechanism. The company correctly points out that the use of the phrase "includes but is not limited to" makes the statutory list of renewable energy resources in in MCL 460.1011(g) expansive

[62] DTE, 57.
[63] MCL 460.1011(i).
[64] MCL 460.1005(i).
[65] MCL 460.1221(i).

and illustrative rather than exclusive.[66] But the items listed in the definition are illustrative of energy sources, that is renewable fuels (e.g. biomass, landfill gas, etc.) or root sources of energy (e.g. solar energy, wind energy, etc.), and co-located energy storage is not a type of fuel or a root source of energy, but rather simply entails the storage of energy already generated.[67] This PFD also does not interpret the descriptive definition of "renewable energy resource" at MCL 460.1011(g)[68] to encompass energy storage because battery storage does not "naturally replenish" but rather requires both human construction and human intervention to recharge. Further, storage does not minimize the output of toxic material in the conversion of energy as required by the definition because its purpose is to store rather than generate energy.[69] Accordingly, this PFD concludes that battery storage is not a "renewable energy resource" as contemplated in the statute. Even if storage could be considered a renewable energy resource, this PFD would still recommend cost recovery through base rates as directed by MCL 460.1101(4) for the reasons previously discussed above in relation to renewable energy systems.

Finally, this PFD does not agree with the company's alternative argument that cost recovery of co-located storage is permissible through MCL 460.1047(2)(a)(vii).[70] Co-located energy storage is an optional cost incurred at the company's discretion. It is not,

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[66] DTE, 56, fn 20 and 21.
[67] See MCL 460.1011(g) (defining renewable energy resource and listing examples of resources that do and do not qualify as a renewable energy resource.).
[68] That provision states in pertinent part that the term renewable energy resource "means a resource that naturally replenishes over a human, not a geological, time frame and that is ultimately derived from solar power, water power, or wind power. . . . A renewable energy resource comes from the sun or from thermal inertia of the earth and minimizes the output of toxic material in the conversion of the energy[.]" MCL 460.1011(g).
[69] See MCL 460.1011(g).
[70] That provision states in pertinent part that the ICOC can include, among other things, "Any additional electric provider costs determined by the commission to be necessarily incurred to ensure the quality and reliability of renewable energy used to meet the renewable energy standards." MCL 460.1047(2)(a)(vii).

as the company suggests, an additional cost that is "necessarily incurred to ensure the quality and reliability of renewable energy used to meet the renewable energy standards."[71]

c. Definition of Co-located Energy Storage

This PFD recommends that, for storage assets, there should be no distinction for cost recovery purposes regardless of whether the asset is standalone or co-located with renewable generation. Accordingly, this PFD sees no clear need to specifically define co-located storage. But if the Commission reaches a different conclusion on that issue, then this PFD agrees with the company and recommends that co-located energy storage be defined as energy storage that shares the MISO point of interconnection with the co-located renewable energy resource. This PFD agrees with the company that the other facets of Staff's proposed definition regarding projects in which storage was added after a renewable resource was constructed are unduly restrictive and have not been adequately justified. Accordingly, this PFD would not recommend adopting those aspects of Staff's definition.

d. Manner of Installation of Co-located Energy Storage

As to Staff's unopposed recommendation that the company install co-located storage assets in a manner that allows it to optimize charging using both the shared interconnected renewable energy resource(s) and the grid itself,[72] this PFD agrees that this would provide efficiency, and other grid benefits. Accordingly, this PFD recommends

[71] MCL 460.1047(2)(a)(vii).
[72] See 2 Tr 31.

that the Commission recommend that co-located storage should be able to charge from both the renewable energy asset and from the grid itself.

B. Transfer Price Update to Include Carbon Capture & Storage

1. Testimony

Mr. Kopinski testified that the basis for the company's proposed 2024 MPSC Staff Transfer Prices is Staff's projection of the total cost of a natural gas combined cycle gas turbine (NGCC or CCGT), with the transfer price based on the levelized cost of energy (LCOE) of a CCGT for the base year 2028 and the levelized natural gas price drawn from the U.S. Energy Information Administration's (EIA's) projection of natural gas prices at the Henry Hub.[73] Previously approved transfer price schedules now must include transfer price projections through 2045, with the extended price projections based on a Consumer Price Index (CPI) inflation factor as reflected in Exhibit 20.1.[74] This is consistent with Staff's methodology in Case No. U-15800, and the company found Staff's methodology to be reasonable for the purpose of determining the transfer price schedules.[75]

Mr. Jester acknowledged the company's use of Staff's approved transfer price methodology, but asserted that this is now inappropriate because the methodology should include not only the LCOE of a CCGT over a 20-year period, but also the costs of carbon capture and storage (CCS).[76] He noted that Michigan's adoption of Clean Energy Standards in section 51 of PA 235 requires that 80% of electricity sales must come from a clean energy resource between 2035 and 2039, and that 100% of sales must come

[73] 3 Tr 534-535. See also Exhibit A-20 Schedules A1 – A3.
[74] 3 Tr 534.
[75] 3 Tr 534-535. See also Exhibit A-20 Schedule A1.
[76] 2 Tr 146.

from clean energy starting in 2040. To comply as a clean energy resource, PA 235 requires that CCS must be at least 90% effective in capturing and storing carbon dioxide after 2035, and the U.S. Environmental Protection Agency (EPA) adopted a rule in 2024 requiring new CCGT plants to have 90% effective CCS as of January 1, 2032.[77] Mr. Jester acknowledged that the EPA's rule has been subjected to legal challenges, but the rule had not been stayed in the meantime.[78] He also commented that including the cost of CCS in the transfer price would eliminate the ICOC in 2029 and in subsequent years.[79]

As a result of the clean energy standards, Mr. Jester asserted that it would not be prudent to build a new CCGT plant without CCS; therefore, the transfer price should now account for CCS.[80] Noting differences in proxy plant capacity between Staff and EPA calculations, Mr. Jester recommended adopting an incremental addition to the transfer price based upon compliance cost estimates from the EPA with adjustments for inflation, which he calculated would increase the estimated cost of CCS to an additional $22.66/MWh.[81] He also recommended that the Commission direct Staff to prepare a modified method for determination of the transfer price to incorporate CCS, and that the company plan in its next REP amendment to disburse any final projected regulatory liability back to customers.[82]

In rebuttal, Mr. Harlow asserted that Staff's current methodology is not improper, even considering Michigan's updated energy legislation, because it represents the price

[77] 2 Tr 146-147, 149.
[78] 2 Tr 147.
[79] 2 Tr 149.
[80] 2 Tr 147.
[81] 2 Tr 148.
[82] 2 Tr 148-149.

that "a Michigan Electric provider would pay if it were to obtain energy and capacity from the market through long term power purchase agreements."[83] He explained that most of Michigan's rate-regulated utilities are MISO market participants, allowing them to enter into power purchase agreements (PPAs) within MISO, but from jurisdictions not subject to Michigan's clean energy standards.[84] Mr. Harlow agreed that Staff's transfer price methodology could be reviewed if the Commission believed it appropriate, but he recommended that this should be done by directing Staff to convene a workgroup including all rate-regulated utilities and interested parties to review the "many potential options" for whether and how to update the transfer price methodology.[85]

Ms. York, on behalf of ABATE, testified that it was premature to determine if changes should be made to the transfer price methodology. She contended that MEC-SC's proposed change would affect multiple Michigan utilities rendering it more appropriate to consider any changes in the context of a workgroup.[86] She also commented on Mr. Jester's assertions regarding ICOC, noting that Mr. Jester does not suggest a method for disbursing a regulatory liability balance to customers if the ICOC becomes negative and grows the regulatory liability balance, with Mr. Jester instead capping the annual regulatory liability balance in his workpaper.[87]

Ms. York highlighted that the company's most recent IRP modeling did not show any material long-term need for generation capacity beginning in the next 5 years, and

[83] 2 Tr 35.
[84] 2 Tr 35.
[85] 2 Tr 34-36.
[86] 2 Tr 121-124.
[87] 2 Tr 123-124.

the modeling did not "select" a CCGT with CCS until 2035.[88] She further testified that natural gas advanced combustion turbines are used to establish cost of new entry (CONE) in the MISO market, with a change to the standard, particularly the useful life of natural gas advanced combustion turbines, to be considered in mid-2025.[89] Ms. York concluded that more time for deliberation on changes to transfer price methodology would allow for "consideration of discussions at MISO and discussion of the issue through a generic workgroup."[90]

2. Briefing

In its initial brief, the company elaborates upon Mr. Kopinski's testimony regarding the renewable energy generation expense projected for 2022 through 2045 and closely tracks Mr. Kopinski's testimony regarding transfer price schedules.[91] The company's initial brief did not take a position on the need for an update to the transfer price methodology.

Staff's brief largely summarizes testimony from Mr. Harlow, Mr. Bilyeu,[92] and Mr. Kopinski, adding that both Staff and ABATE believe that review of the transfer price methodology in this case is premature.[93] Staff asserts that the transfer price is "designed to ensure that renewable energy projects receive a fair price, which the Company is able to recover through the PSCR, if the contract price is higher than the transfer price."[94] Staff

[88] 2 Tr 122-123.
[89] 2 Tr 123.
[90] 2 Tr 124.
[91] DTE, 31-35; see also Exhibit A-20.
[92] Mr. Bilyeu presented the transfer price as part of DTE Electric's overview of the case. 3 Tr 282-283 & 289.
[93] Staff, 2, 16-20
[94] Staff, 17.

reiterates that there are many ways that the current transfer price methodology might change in the future, with MEC-SC's recommendation only one such option, particularly where electric utilities have the option to purchase electricity from outside Michigan.[95] And Staff again recommends that, consistent with past practice and because there are "many possible views on what transfer price methodology should be," the Commission should order a workgroup to consider transfer price methodology and approve any new methodology as part of a reconciliation case.[96]

ABATE's brief echoes Ms. York's testimony.[97] ABATE breaks down that inclusion of CCS in the transfer price would increase it by $22.66/MWh, or 36.4% over the 2024 transfer price of $62.32/MWh calculated by Staff and requested by the company.[98] ABATE outlines the development of Staff's current methodology, again notes that the company's current IRP modeling does not adopt a CCGT with CCS until 2035, and asserts that the appropriate transfer price proxy of the future cannot be predicted, as most of the models select solar, and not an CCGT plant, going forward.[99] ABATE further emphasizes that the Commission sought to bring transparency to the process of calculating the transfer price and convened a technical conference to address the issue, after which most transfer price schedules have been developed using the methodology proposed by Staff in Case No. U-15800.[100] ABATE also argues that changing the transfer price in this proceeding would have implications that would affect ICOC and the

[95] Staff, 17-20.
[96] See Staff, p. 16-20.
[97] ABATE, p. 7-13.
[98] ABATE, p. 7.
[99] ABATE, p. 9-11.
[100] ABATE, p. 8-9.

company's regulatory liability balance.[101] Accordingly, ABATE contends that the current transfer price methodology should be maintained in this case because a change would be "premature and unreasonable," and that, if the methodology is to be revisited, it should be done carefully and with transparency, without "dramatically" increasing costs in the current case.[102]

MEC-SC summarizes the history of the transfer price methodology, as well as the testimony regarding transfer price methodology in the case.[103] MEC-SC presents seven reasons that it would be imprudent to reject its recommendation and to instead convene a workgroup to discuss the transfer price. First, MEC-SC contends that Staff provided no details regarding the duration of the proposed workgroup and that the current methodology was adjudicated in renewable energy reconciliation cases that followed a single 2012 technical conference on the issue.[104] Second, MEC-SC asserts that, because the 2012 technical conference did not achieve consensus, then consensus is not necessary now.[105] Third, MEC-SC contends that it is not necessary that every regulated utility must participate because the Commission sets a transfer price for each provider, and does not set a uniform transfer price for all regulated electric providers.[106]

MEC-SC continues that the fourth reason a workgroup is unnecessary is because it would result in an informational filing only with every provider still able to propose their own transfer price.[107] Fifth, MEC-SC contends that the notice received through Staff's

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[101] ABATE, p. 11-12.
[102] ABATE, 7, 12-13.
[103] MEC-SC, 53-60.
[104] MEC-SC, 61.
[105] MEC-SC, 61-62.
[106] MEC-SC, 62.
[107] MEC-SC, 62.

informational filings in Case No. U-15800 provides sufficient notice to all providers rendering the additional notice provided by a workgroup unnecessary.[108] Sixth, MEC-SC argues that the Commission has undisputed authority to provide direction on transfer price in this case whether or not consensus is reached in a future workgroup.[109] Seventh, MEC-SC argues that the Commission cannot approve the proposed transfer price and direct a future workgroup to "fix" the transfer price later because doing so is not based upon substantial evidence, and a transfer price that is too low will affect other aspects of the amended REP including ICOC and regulatory liability balances.[110]

MEC-SC emphasizes that, contrary to Mr. Harlow's suggestion, a Michigan electric provider could not circumvent compliance with clean energy standards under PA 235 by entering a PPA with an out-of-state plant that lacked CCS.[111] Accordingly, MEC-SC argues that there is no substantial evidence in the record to support approving the current proposed transfer price schedule, which is based upon the costs of a CCGT plant without CCS.[112] MEC-SC recommends that the Commission should not approve the company's proposed transfer price at present, and instead should reserve the issue for adjudication in the company's 2024 RE Reconciliation case. Additionally, the Commission should direct Staff, in that reconciliation case, to propose transfer prices that add the cost of CCS to the traditional transfer price methodology.[113] In the alternative, if the Commission prefers a workgroup, it should direct that a technical conference be convened within 30

[108] MEC-SC, 63.
[109] MEC-SC, 63.
[110] MEC-SC, 63-64.
[111] MEC-SC, 65-66.
[112] MEC-SC, 64-66.
[113] MEC-SC, 67.

days, with a report to be issued in 90 days (as was done in Case No. U-16582), and with reservation of the transfer price issue to the company's 2024 RE reconciliation, subject to the explicit statement that the company's proposed transfer price schedule is not approved in the instant case.[114]

ABATE's reply brief further expands on its earlier arguments in favor of maintaining current transfer price methodology until a workgroup can be established.[115] ABATE contends that there is insufficient evidence, and nothing in MCL 460.1047(2)(b)(iv), that would support the idea that the most likely proxy plant will be a CCGT with CCS going forward. ABATE contests both the assumption that CCGT will be the conventional generation built in the near future, and that the transfer price should be based on the levelized cost of a CCGT plant.[116] ABATE also repeats its contention that MISO may be revisiting the use of natural gas advanced combustion turbines to establish its CONE later this year as further evidence that a natural gas plant may not be the appropriate transfer price plant proxy going forward.[117]

ABATE contends that a transfer price workgroup would not break with precedent or take an inordinate amount of time, as the Commission ordered the technical conference that created the current methodology to conclude in a 90 day timeframe.[118] According to ABATE, the Commission ordered a technical conference in Case No. U-16582 in the face of similar transfer price arguments from MEC.[119] Summarizing MEC-

[114] MEC-SC, 67.
[115] ABATE Reply, 5-11.
[116] ABATE Reply 6-9.
[117] ABATE Reply, 8-9.
[118] ABATE Reply, 9-10.
[119] ABATE Reply, 10-11.

SC's procedural claims against a workgroup, ABATE then quotes the Commission's recognition that "transfer prices are a contentious issue," arguing that the concerns regarding transparency that led to the technical conference creating the current methodology are even more salient now due to the expansion of renewable energy and changes in energy markets.[120] ABATE asserts that "MEC-SC urges an immediate cost increase based on inadequately supported assumptions regarding future utility compliance with clean energy plan requirements effective over a decade from now."[121] As a result, ABATE recommends rejecting MEC-SC's proposed change to transfer price calculation methodology, instead advocating for the creation of some form of workgroup to revisit Staff's preferred transfer price methodology.[122]

The company's reply brief summarizes Staff's, ABATE's, and MEC-SC's positions regarding transfer pricing and methodology, and requests that the transfer price revenue recovery be approved as it exists in the Amended REP.[123] The company maintains that there is nothing wrong or inaccurate with the current methodology or assumptions for forecasted transfer prices. Forecasted transfer prices will be updated as Staff releases updated transfer price schedules, and actual transfer prices assigned to projects will use the approved transfer price schedule when a project receives Commission approval.[124]

MEC-SC's reply brief reiterates the arguments and recommendations set forth in testimony and in its initial brief, focusing on a need for compliance with PA 235.[125] In

[120] ABATE Reply, 10-11.
[121] ABATE Reply, 11.
[122] ABATE Reply, 11.
[123] DTE Reply, 20-24.
[124] DTE Reply, 23-24.
[125] MEC-SC Reply,1; 7-17.

response to Staff, MEC-SC indicates it agrees that new transfer prices should be approved in reconciliation cases, but otherwise asserts that the company's proposed transfer prices are flawed, and the transfer price schedule numbers should not be left to a workgroup "to fix them."[126] Neither past transfer price forecasts, nor Staff's filing in Case No. U-15800, are binding, and they do not preclude review of the transfer price schedule in this case.[127] In support of the proposition that the forecasted transfer price schedules should be considered in the instant case, MEC-SC cites a passage from the November 7, 2024, order in Case No. U-21291, where the Commission rejected Staff's recommendation to consider an increase of the Low-Income Assistance credit as part of the Energy Affordability and Accessibility Collaborative instead of in the company's rate case.[128]

MEC-SC continues to urge the rejection of a lengthy workgroup process to reconsider transfer price methodology, and MEC-SC repeats its request for a single technical conference if MEC-SC's proposed methodology is not adopted outright, with proposed changes to be adjudicated in conference participants' respective reconciliation cases.[129] MEC-SC takes issue with ABATE's citation to the company's most recent IRP case, Case No. U-21193, as both inadmissible and irrelevant regarding the company's ability to meet renewable energy credit standards since the IRP addressed capacity requirements.[130] MEC-SC argues that the transfer price schedule is set forth in this case and, as a result, it is not premature to consider the reasonableness and prudence of the

[126] MEC-SC Reply, 8-9.
[127] MEC-SC Reply, 9.
[128] MEC-SC Reply, 10-11.
[129] MEC-SC Reply, 10-11.
[130] MEC-SC Reply, 11-12.

schedule now. MEC-SC adds that the company has not established the reasonableness or correctness of the currently proposed transfer price schedule.[131]

MEC-SC also rejects ABATE's arguments noting that the natural gas advanced combustion turbines (CTs) used to establish MISO CONE are completely different from CCGTs. Per MEC-SC, ABATE's linking of CCGTs to uncertainty in MISO CONE standards is a false analogy because no one has presented evidence that a CT should be used as a transfer price proxy.[132] The analogy is also factually flawed, as the actual minutes cited by ABATE only propose consideration of adjusting the useful life duration of a CT for CONE calculation, and do not, in MEC-SC'S view, question the use of CT as a proxy for calculating MISO's CONE.[133] MEC-SC posits that there continues to be no evidence that any regulated utilities plan to enter into PPAs using CCGTs without CCS in other states. MEC-SC concludes by asserting that "[n]o one has offered any evidence that [CCS] costs will not be required" such that use of CCGTs with CCS should be the proxy standard going forward due to the need to comply with PA 235.[134]

3. Conclusion and Recommendation

This PFD agrees with MEC-SC that the current transfer price methodology likely needs to be updated to account for CCS costs or alternatively should be revisited to find a different methodology that does not rely solely on a CCGT plant as a proxy.

Staff's current methodology, which has largely been accepted by electric providers, utilizes the 20-year levelized cost of a new CCGT plant.[135] However, as MEC-SC has

[131] MEC-SC Reply, 13.
[132] MEC-SC Reply, 13-14.
[133] MEC-SC Reply, 14.
[134] MEC-SC Reply, 16.
[135] See Exhibit MEC-10, p. 2.

argued, at the federal level, a new 2024 EPA final rule requires new gas plants to operate with 90% effective CCS by 2032, although that rule is the subject of a legal challenge.[136] At the state level, PA 235 directs that electric providers in Michigan must have a clean energy portfolio of 80% by 2035 and 100% by 2040.[137] Under PA 235, a natural gas plant can be considered a "clean energy system," but only if it employs CCS technology that is at least 90% effective.[138]

Given these evolving clean energy standards, any new gas-fired power plant in Michigan would require CCS in 2032 at the earliest if the EPA final rule remains in effect, and if not, then possibly by 2035 or by 2040 at the latest under PA 235. Thus, if the transfer price methodology is based upon the hypothetical 20-year levelized cost of a new CCGT plant, then that plant will need to incorporate CCS (and its attendant costs) sometime within that 20-year period, whether initially constructed with CCS or whether retrofitted later.

This PFD is not persuaded by Staff's argument that the current methodology remains adequate because a utility could hypothetically enter a PPA involving an out-of-state CCGT plant that is not subject to Michigan's clean energy laws. First, Mr. Harlow himself acknowledged that it was "not likely" that a Michigan utility would enter into such a PPA.[139] Second, this PFD is not persuaded that signing such a PPA would excuse a Michigan utility from complying with PA 235 because the act does not appear to

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[136] 2 Tr 147, citing Environmental Protection Agency, *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,* 89 FR 39798 (May 9, 2024).
[137] MCL 460.1051(1)(a) and (b).
[138] MCL 460.1003(i)(*ii*).
[139] 2 Tr 69-70.

contemplate such an exception, nor has Staff cited any legal authority to support its argument in this vein.[140] Finally, if the federal EPA final rule survives legal challenge or is not otherwise repealed, then presumably any new gas plant in the United States would soon need to include CCS.

However, this PFD does not agree with MEC-SC that the transfer price should simply be updated in this case by implementing the CCS cost adjustments proposed by Mr. Jester. As suggested by Staff and ABATE, there may be different approaches to the transfer price that could be used outside of the existing methodology that relies on a CCGT plant as a proxy.[141] Thus, while it is not unreasonable per se to update the current approach by adding the estimated cost of CCS, that approach is not the only approach, and this PFD recommends evaluating all reasonable methods.

Further, this PFD agrees with Staff and ABATE that, even if a consensus cannot be reached, there is value in gathering input from regulated utilities and other interested parties regarding the best method of calculating the transfer price. However, this PFD also agrees with MEC-SC that the process of gathering that input should be expeditious rather than open-ended and indefinite. Accordingly, this PFD recommends that the Commission order a workgroup or conference of limited duration to make recommendations regarding whether and how to update the current transfer price methodology considering evolving clean energy standards. This recommendation aligns with the Commission's previous action in Case No. U-16582, which convened a technical

[140] Again, MCL 460.1051(1) requires a clean energy portfolio of 80% by 2035 and 100% by 2040. See also MCL 460.1003(g) (defining clean energy portfolio), MCL 460.1003(e) (defining clean energy) and MCL 460.1003(i) (defining clean energy system and allowing a gas plant with CCS to satisfy that definition).
[141] See 2 Tr 35-36.

conference with a 90-day duration to initially develop the appropriate methodology for the transfer price.[142] This PFD further recommends that such a workgroup or conference should have an end date such that the Commission could decide the issue of an appropriate transfer price methodology in the next scheduled renewable energy reconciliation cases.

In the interim, this PFD does not recommend approving the company's proposed transfer price schedule at this time given that it does not account for the changes in law discussed above that affect the current CCGT-based transfer price methodology, and this PFD suggests that the issue should be reserved for the corresponding reconciliation case.

C. REP Regulatory Liability Balance

1. Testimony

Mr. Bilyeu explained that the company intended to create an accumulation of reserve funds and carry forward a regulatory liability, as well as avoid the creation of a regulatory asset by imposing a surcharge, if necessary.[143] He asserted that maintaining a regulatory liability was proper after the passage of PA 235 because the Commission stated in its April 25, 2024, Order in Case No. U-21568 that "any regulatory liability balances should continue forward and be addressed in renewable reconciliation proceedings as is the current practice."[144] He acknowledged that the amended REP showed a regulatory liability of $1.5 billion accumulating by 2045 (see Exhibit A-2), but he stated that the company does not intend to actually accrue that amount, changes in

[142] See Case No. U-21658, December 20, 2011, Order, pp 16-17.
[143] 3 Tr 294, 295.
[144] 3 Tr 295.

assumptions could impact the ending balance, and the company focused on the initial three years of the plan up to 2027 after which the company will file its next REP.[145]

Mr. Jester testified that, if the Commission accepts his recommendation concerning transfer prices, then a regulatory liability will be unnecessary because there will be no ICOC going forward.[146] He testified that if the Commission accepts the company's proposals regarding the transfer price, then he supported using regulatory liabilities and regulatory assets to avoid "unnecessary variations" in customer billing. Specifically, he recommended that if the company's amended REP proceeds as projected, that a surcharge should not be imposed to avoid a temporary regulatory asset.[147]

Mr. Jester addressed the company's projected accumulation of a large regulatory liability by 2045. He asserted that the Commission "should require in reconciliation that any positive regulatory liability balance be refunded to customers as a bill credit in the reconciliations."[148] He also opined that if the Commission is confident that the projected 2045 regulatory balance will be positive and significant, then that can be reduced by bill credits in advance of the appearance of the current regulatory liability balances.[149] Mr. Jester opined that this could be done even if it contributes to a temporary regulatory asset balance.[150]

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[145] 3 Tr 295.
[146] 2 Tr 152.
[147] 2 Tr 152.
[148] 2 Tr 152.
[149] 2 Tr 152.
[150] 2 Tr 152.

In rebuttal, Mr. Bilyeu disagreed with the suggestion that the company should maintain a regulatory asset rather than implement a surcharge. He opined that it was "crucial" for the company to be allowed to maintain a regulatory liability consistent with PA 295, as amended by PA 235.[151] He explained that regulatory liabilities are crucial for a revenue recovery system based on the PSCR transfer approach and that the use of regulatory liabilities "is consistent with legislation, helps ensure the economic viability of committed projects, and minimizes the need for a separate surcharge mechanism."[152] He also asserted that the Commission's April 25, 2024, Order in Case U-21568 allows for the continued use of regulatory liabilities with the Commission agreeing that regulatory liability balances should continue forward and be addressed in renewable reconciliation proceedings.[153]

Mr. Bilyeu argued that Mr. Jester's recommendations were inconsistent in that he urged the use of regulatory asset or liability balances to avoid surcharges while also asserting that in reconciliation proceedings positive regulatory balances should be refunded to customers. He explained that "[i]f the Company were to refund any positive regulatory liability balance to customers, then the Company would need to implement a surcharge in certain years that would have otherwise drawn from the regulatory liability."[154]

Mr. Bilyeu rejected the idea that surcharges were "unnecessary variations" in billing, and in any event, he reiterated that the company did not propose to implement a

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[151] 3 Tr 313.
[152] 3 Tr 312.
[153] 3 Tr 313.
[154] 3 Tr 313.

surcharge in this proceeding.[155] Mr. Bilyeu also addressed concerns regarding the projections of a large regulatory liability accumulating after 2040. He stated that the company will file multiple amended REPs before 2040, and there will be several opportunities to update and adjust the regulatory liability position, which could include reductions in the forecasted balance.[156]

2. Briefing

The company's briefing echoes the rebuttal testimony of Mr. Bilyeu and argues that it is both reasonable and lawful for the company to maintain a regulatory liability.[157] Additionally, the company argues that "the plain language of MCL 460.1049(3)(b) does not require or otherwise confer the authority to mandate refunding positive regulatory liability balances as recommended by MEC-SC witness Jester."[158] The company contends that Mr. Jester's recommendation that positive regulatory balances should be refunded to customers in reconciliation proceedings is not consistent with PA 235, goes beyond the Commission's statutory authority, and is not an appropriate request in the context of a REP proceeding.[159]

MEC-SC argues that the company's citation to the Commission's April 25, 2024, Order in Case U-21568 is misleading because the Commission was specifically addressing how to handle residual liability balances from PA 342 for providers that did not have a renewable portfolio requirement going forward.[160] MEC-SC contends that the

[155] 3 Tr 314.
[156] 3 Tr 314.
[157] See DTE, 38-40.
[158] DTE, 39.
[159] DTE, 39.
[160] MEC-SC, 70.

Commission has "never endorsed DTE's position that the company could carry on building up large accumulated reserve balances and recording regulatory liabilities year after year despite key changes in the law."[161] In fact, MEC-SC contends that changes in the law brought about by PA 235 require the company to adjust the balance of the regulatory liability in each reconciliation to only the amount necessary to cover the ICOC.[162]

First, MEC-SC notes that under PA 295 of 2008, the Commission was required to approve a regulatory liability and set a minimum balance if one was proposed; however, MEC-SC contends that such a provision was omitted in PA 235.[163]

Second, MEC-SC asserts that in reconciliations under PA 295 of 2008 (and as amended by PA 342 of 2016), the Commission was formerly required to ensure that the revenue recovery mechanism was projected to maintain a minimum balance so that a regulatory asset did not accrue.[164] However, MEC-SC contends that PA 235 now states in pertinent part that "[a]ny regulatory asset or regulatory liability accrued during the reconciliation period shall be used to adjust the revenue recovery mechanism and reflected in the incremental cost of compliance for the following calendar year."[165] MEC-SC states that the requirement to ensure a minimum balance of accumulated funds for the provider has been deleted, and that the new language of PA 235 does not allow accumulated reserve funds or regulatory balances to be built up or carried forward from

[161] MEC-SC, 70.
[162] MEC-SC, 68.
[163] MEC-SC, 70-71 (citing former MCL 460.1021(4) and 3 Tr 402-403; 410-411).
[164] MEC-SC, 71 (citing former MCL 460.1049(3)).
[165] MEC-SC, 71 (quoting MCL 460.1049(3)(b)).

year to year because adjustments have been tied to the years immediately preceding and following the reconciliation period.[166]

Third, MEC-SC contends that if any doubt remains, another section of PA 235 "puts the issue to rest" by explicitly requiring providers to adjust the revenue recovery mechanism by the difference between the amount recovered for the year and the ICOC for the year.[167] MEC-SC argues that these changes in the statute do not allow for the provider to continuously accumulate reserve funds and that there is no other plausible interpretation for these provisions of PA 235.[168]

MEC-SC also rejects the rebuttal testimony offered by Mr. Bilyeu. MEC-SC first states that Mr. Bilyeu presupposes that it is the company's prerogative to carry a regulatory liability from year to year, but the new provisions of PA 235 do not grant the company that discretion.[169] Next, MEC-SC argues that the company assumes it can decide whether to adjust the reserve balance in future REP cases, but PA 235 plainly requires adjustments to be made each year in the reconciliation cases, not in REP amendment cases.[170] MEC-SC contends that the company provided no evidence that there was unnecessary risk from having to recover costs after an expenditure is made rather than before it, and in any event, the company failed to address or acknowledge the changes in law caused by PA 235 and outlined in MEC-SC's argument.[171]

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[166] MEC-SC, 72.
[167] MEC-SC, 72 (citing MCL 460.1049(4), i.e. Section 49(4) of PA 235)).
[168] MEC-SC, 72.
[169] MEC-SC, 73.
[170] MEC-SC, 73-74.
[171] MEC-SC, 74.

MEC-SC recommends that the Commission reject the company's projected accumulated reserve funds and regulatory liability balances and that it should direct the company to make the adjustments required by PA 235 each year in the appropriate reconciliation cases.[172]

The company replies that MEC-SC's argument should be rejected because MCL 460.1022(2) establishes that amended REPs shall establish a mechanism for the recovery of the ICOC within customer rates and MCL 460.1045(1) requires the Commission to determine a revenue recovery mechanism that permits recovery of the ICOC to implement the amended REP.[173] The company contends that Act 235 does not prohibit a utility from maintaining a regulatory liability if it can demonstrate the balance is needed to recover an ICOC in a future year. Specifically, the company points out that MCL 460.1049(2) establishes that during a reconciliation case the company can propose modifications to the revenue recovery mechanism to ensure recovery of the ICOC with the RES.[174] The company asserts that under MEC-SC's approach, the company would accrue a regulatory asset for eight years resulting in a separate customer surcharge that the company seeks to avoid.[175]

MEC-SC replies that while the company seeks approval to maintain an accumulation of reserve funds and maintain a regulatory liability, the provision of law allowing it to do so no longer exists in PA 235.[176] MEC-SC emphasizes that the company "is requesting approval to do something that was authorized under the prior statute but is

[172] MEC-SC, 74.
[173] DTE Reply, 25.
[174] DTE Reply, 25.
[175] DTE Reply, 26.
[176] MEC-SC Reply, 27.

not authorized under the current one."[177] MEC-SC asserts that under caselaw the deletion of provisions from a statute has legal significance that must be given effect, and PA 235 deleted statutory provisions that previously authorized the company to request and carry forward a regulatory liability.[178] MEC-SC argues that "[w]hile PA 235 recognizes that a utility may record a regulatory liability, that authorization is only for the reconciliation period – not for years on end."[179] MEC-SC also responds that PA 235 removed language requiring the Commission to prevent a regulatory asset from accruing and now expressly authorizes the accrual of a regulatory asset, which like a regulatory liability, must be adjusted in a reconciliation proceeding.[180]

MEC-SC rejects the company's argument that the Commission lacks authority under PA 235 to require regulatory liability balances to be refunded to customers. MEC-SC contends that nothing in the statute limits the revenue recovery mechanism to only a positive surcharge, and the Commission has authority under precedent to require a refund of customers' own money that is held by a utility.[181] MEC-SC contends that it is unclear how the company could avoid accumulating a billion dollar regulatory liability without refunds, and that the company could manage this issue the same way as peer utility Consumers Energy plans to by incurring a regulatory asset and reducing the regulatory asset to zero over time as transfer price revenue exceeds the ICOC.[182] MEC-SC asserts that the Commission need not decide the issue of refunds until a reconciliation proceeding

[177] MEC-SC Reply, 27.
[178] MEC-SC Reply, 27-28.
[179] MEC-SC Reply, 28.
[180] MEC-SC Reply, 29 (citing MCL 460.1049(3)).
[181] MEC-SC Reply, 29-30.
[182] MEC-SC Reply, 31-32 (citing Case No. U-21816).

occurs, and that the Commission need only disapprove of the company's plan to accumulate a large reserve balance of funds and carry forward a regulatory liability year after year.[183]

3. Conclusion and Recommendations

This PFD agrees with MEC-SC that the company's reliance on a citation to the Commission's April 25, 2024, Order in Case No. U-21568 does not fully support its position. It is true that the Commission's Order stated: "The Commission agrees that any regulatory liability balances should continue forward and be addressed in renewable reconciliation proceedings as is the current practice."[184] But in context, the Commission's statement addressed the treatment of residual regulatory liability balances for electric providers that would not have a renewable portfolio requirement under PA 235 going forward because they satisfied an exception in PA 235 for nuclear energy found in MCL 460.1028(3).[185] In other words, this PFD does not interpret that portion of the Commission's Order to suggest that all regulatory liability balances should be treated in the same way after the passage of PA 235 as they were before the passage of that act.

This PFD also agrees with MEC-SC that statutory changes brought about by PA 235 do not support the company's position on the maintenance of a large regulatory liability through successive years. Specifically, Section 21 of PA 295 of 2008 contained a provision that allowed an electric provider to propose—and required the Commission to approve—a revenue recovery mechanism that would result in the accumulation of a minimum balance of accumulated reserve funds and the creation of a regulatory

[183] MEC-SC Reply, 32.
[184] Case No. U-21568, Order, April 25, 2024, p 16.
[185] See Case No. U-21568, Order, April 25, 2024, p 15-16.

liability.[186] By contrast, this language does not appear in PA 235, which does not contain a Section 21,[187] and the company does not cite to any other language of PA 235 that expressly approves the long-term accumulation of a regulatory liability. Further, MEC-SC is correct that under caselaw, the deletion of statutory provisions generally indicates the legislative intent to withdraw or negate the effect of the deleted provisions.[188] Indeed, "[a] change in statutory language is presumed to reflect a change in the meaning of the statute."[189]

PA 235 also made additional changes to renewable cost reconciliation proceedings that call into question the ability of an electric provider to accumulate a regulatory liability across several years. Specifically, PA 235 amended MCL 460.1049(3) by removing the requirement for the Commission to ensure that the recovery mechanism is projected to avoid the creation of a regulatory asset and to appropriately adjust the minimum balance of accumulated reserves under Section 21 (which, again, no longer exists in PA 235).[190] Instead, PA 235 amended MCL 460.1049(3)(b) to state that the Commission must adjust the revenue recovery mechanism for the incremental cost of compliance and adds that "[a]ny regulatory asset or regulatory liability accrued during the reconciliation period shall be used to adjust the revenue recovery mechanism and reflected in the incremental cost of compliance for the following calendar year."[191] PA 235 further added a new section, MCL 460.1049(4), stating that in its reconciliation order, "the

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[186] See former MCL 460.1021(4) (now repealed); 2008 PA 295.
[187] See generally 2023 PA 235; MCL 460.1001 *et seq*.
[188] See *In re Mich Con Gas Co*, 293 Mich App 360, 368; 810 NW2d 123 (2011).
[189] *Eaton Farm Bureau v Eaton Twp*, 221 Mich App 663, 668; 561 NW2d 884 (1997).
[190] See generally 2023 PA 235; see also current MCL 460.1049(3).
[191] MCL 460.1049(3)(b).

commission shall require an electric provider to adjust the revenue recovery mechanism by any difference between the net amount determined to have been recovered and the net amount needed to recover the electric provider's incremental cost of compliance."[192]

This PFD agrees with MEC-SC that the overall effect of the statutory changes discussed above appears to be that they: (1) no longer require the Commission to approve any regulatory liability proposed or prevent the accumulation of a regulatory asset, and (2) generally hinder an electric provider from banking surplus recoveries across multiple years in order to accumulate a large regulatory liability. While PA 235 acknowledges that a provider may record a regulatory liability or a regulatory asset, the act references that capability within the 12-month reconciliation period and does not appear to specifically contemplate it extending it across successive years.[193] This fact appears to be particularly salient given PA 235's newly required adjustments in yearly reconciliation proceedings to the revenue recovery mechanism and ICOC based upon the accumulated regulatory liability or asset,[194] and the requirement to adjust the revenue recovery mechanism by the difference between the net amount determined to have been recovered and the net amount needed to recover the ICOC.[195] In other words, these required adjustments appear designed to prevent the accumulation of a large regulatory liability across several successive years. The company offered no alternative interpretation for these provisions, and it appears that the company has not changed its

[192] MCL 460.1049(4).
[193] See generally MCL 460.1049(1) (stating that this section of the statute applies to a rate regulated electric provider that "has recorded a regulatory asset or regulatory liability under this subpart for the last 12 months.").
[194] MCL 460.1049(3)(b).
[195] MCL 460.1049(4).

fundamental approach to the treatment of accumulated reserve funds and regulatory liabilities after the passage of PA 235.[196]

The company's briefing neglects to directly address or grapple with the effect of the new language contained in MCL 460.1049(3)(b) and MCL 460.1049(4) after the passage of PA 235. The company contends that PA 235 does not prohibit maintaining a regulatory liability balance if it can demonstrate that the balance is needed to recover an ICOC in a future year, and the company cites MCL 460.1049(2) for support, which states that "[a]t the renewable cost reconciliation, an electric provider may propose any necessary modifications of the revenue recovery mechanism to ensure the electric provider's recovery of its incremental cost of compliance with the renewable energy standards." But this provision does not negate the yearly adjustments that must be made under MCL 460.1049(3)(b) and MCL 460.1049(4) in reconciliation proceedings. Consequently, it is not clear how this provision supports the company's position regarding the long-term accumulation of reserve funds to create a regulatory liability.

The company's amended REP forecasts regulatory liability balances in future years that fluctuate significantly and vary from tens of millions to several hundred million dollars with the projection surpassing a billion dollars in the 2040s.[197] This PFD recognizes that the company may not actually intend to accumulate a regulatory liability that large, but given the above analysis, this PFD recommends disapproving of the company's plan to accumulate large regulatory liabilities over the plan years because

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[196] In cross-examination, when asked whether the company changed its approach to accumulated reserve funds or the regulatory liability after the passage of PA 235, Mr. Bilyeu stated that the company maintained the same fundamental approach as in previous amended REP cases to avoid adding a surcharge to customer bills. 3 Tr 414-415.

[197] See Exhibit A-2, pp 1-4, line 78 on each page.

doing so appears inconsistent with the operation of PA 235. This PFD declines to address the issue of potential refunds as discussed by the parties because it is not ripe in this case and would be more aptly addressed in reconciliation proceedings.

D. MIGreenPower Expansion and RECs

1. Testimony

Mr. Smith testified that the amended REP proposed adding 300 MW of renewables in 2027, 500 MW in 2028, and 130 MW in 2029 to support customer demand in the MIGreenPower program, a part of the Voluntary Green Pricing (VGP) program.[198] He explained that the company believes that the current portfolio of VGP projects is not adequate to support the program based on forecasted future demand as shown in Exhibit A-33.[199] Mr. Smith also provided a general overview of issues relating to the company's VGP program, including community solar and the purchase of RECs from DG customers, that will be addressed in the company's pending Section 61 VGP filing in Case No. U-21375.[200]

Mr. Harlow did not provide direct testimony about the company's proposed expansion of VGP resources, but he cautioned that the Commission should not consider significant changes to VGP programs in this docket, such as the treatment of RECs from direct generation (DG) customers, because pending Case No. U-21375, which addresses the company's VGP program, is the appropriate venue to examine such issues.[201]

[198] 3 Tr 475.
[199] 3 Tr 475; see also Exhibit A-33.
[200] 3 Tr 476-480.
[201] 2 Tr 26-27.

Ms. York testified that per the company's response to data requests, the proposed additions to VGP capacity are only 67% subscribed for the 2027 additions while the 2028 and 2029 additions are not yet subscribed at all.[202] She testified that she did not oppose the request for additional capacity in 2027 because of the increased RPS requirements and because it is nearly 70% subscribed. However, she opposed the request for additional capacity in 2028 and 2029 because that capacity is not subscribed and because the company has a recent history of transferring a growing amount of unsubscribed VGP asset costs to non-subscribers.[203] Ms. York explained that costs associated with unsubscribed portions of VGP assets are recovered from non-subscribers through a combination of ICOC and the PSCR transfer price.[204] She recommended that the Commission should direct that the company's request for 2028 and 2029 VGP capacity additions should be revisited in the company's next amended REP.[205]

By contrast, Mr. Kenworthy testified in support of the additional VGP resources, and he opined that the proposed expansion of VGP resources aligns with customer demand for clean energy.[206]

In rebuttal, Mr. Smith disagreed with Ms. York stating that MIGreenPower has considerable lead times on both the supply and demand side of the program, and it is necessary to plan several years in advance to procure resources to meet future demand.[207] As an example, he stated that the MISO interconnection process is targeted

[202] 2 Tr 113.
[203] 2 Tr 113-114.
[204] 2 Tr 111.
[205] 2 Tr 114.
[206] 3 Tr 608-609.
[207] 3 Tr 484.

to take between 373 and 463 days, but can sometimes last as long as 5 years.[208] Mr. Smith also testified that business-to-business transactions often take one to two years in order to align the parties involved and close the deal.[209] He asserted that the company believes that the requested capacity will be fully subscribed due to projected customer demand and the need to meet publicly stated corporate sustainability goals and policies.[210] Regarding the concern that non-VGP customers would bear the burden of unsubscribed VGP capacity, he asserted that "[i]n the unlikely event that additional capacity in 2028 and 2029 is not fully subscribed, the excess RECs would be used to meet RPS compliance. Given the increase in the RPS from 15% today to 50% by 2030, these unsubscribed RECs would still provide value to non-VGP customers."[211] He added that new provisions on project allocation set forth in the partial settlement agreement in Case No. U-21172 ensure price parity between participating and non-participating VGP program customers.[212]

Mr. Smith also agreed with Mr. Harlow that changes to the structure of the VGP program, such as the treatment of RECs from DG customers, should be addressed in the company's pending VGP plan in Case No. U-21375. However, he opined that VGP program requests that do not alter the program's structure, such as plans for new resources, are appropriate for consideration in this amended REP case.[213]

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[208] 3 Tr 484.
[209] 3 Tr 485.
[210] 3 Tr 485.
[211] 3 Tr 485.
[212] 3 Tr 485.
[213] 3 Tr 483.

In rebuttal, Mr. Harlow agreed with Ms. York that under-subscribed VGP resources are back-stopped by renewable cost recovery, but he explained that Staff is also concerned with the long lead time associated with development and believes that the company would need to start soon to achieve commercial operation in 2028.[214] He suggested that if the company's VGP forecast was overzealous, then the resources could be converted to RPS eligible assets.[215]

2. Briefing

The company's brief closely tracks and repeats the direct and rebuttal testimony of Mr. Smith.[216] The company agrees that the issue regarding the treatment of RECs from DG customers should be decided in pending Case No. U-21375, but the company asserts that proposed resource additions to the VGP program should be decided in the instant case.[217] The company argues that the record contains robust support for the proposed addition of 930 MW to the VGP program, and the risk of duplicative efforts regarding this specific issue of constructing additional resources does not apply.

Staff's briefing notes that the company discusses details regarding the company's VGP program, but Staff asserts that it "does not opine on those proposals because the VGP filing [in Case No. U-21375] is the appropriate place to address the proposals."[218]

ABATE's brief largely repeats and emphasizes the testimony presented by Ms. York.[219] ABATE argues that it is not reasonable or prudent to approve the 2028 or 2029

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[214] 2 Tr 38.
[215] 2 Tr 38.
[216] See DTE, 47-51.
[217] DTE, 48.
[218] Staff, 14.
[219] See ABATE, 2-7.

buildouts when they are not subscribed and when any RECs generated by the new assets would not even be needed for RPS compliance.[220] ABATE argues that it would be unfair for non-subscribing customers to bear costs of new unsubscribed VGP assets, and that the company's assertions regarding lead times and corporate sustainability goals of unspecified potential customers do not justify approval of new resources.[221]

The company's reply states that while Staff's brief indicates that it was not addressing VGP-related issues, Staff witness Harlow acknowledged the company's proposed additions to the VGP build plan and thereby made it clear that Staff was not recommending the exclusion of this VGP-related proposal from the current case.[222] The company's reply further reiterates points made in its initial brief and also argues that revisiting the request for additional capacity in the company's next amended REP "would not allow enough time for the build to occur by 2028 and 2029."[223]

ABATE's reply emphasizes that the proposed 2028 and 2029 buildouts are not subscribed and that the company "has provided no basis to support the claim that the proposed 2028 and 2029 VGP capacity will be subscribed beyond its own belief, and the RECs associated with this capacity are not needed to meet RPS compliance."[224] ABATE contends that the company's history of overestimating VGP subscription belies the reasonableness of its request, and that the company's concerns regarding the lead time

[220] ABATE, 3-4.
[221] ABATE, 6.
[222] DTE Reply, 32.
[223] DTE Reply, 33.
[224] ABATE Reply, 4.

to acquire resources does not trump its burden to demonstrate that the acquisition of resources is reasonable and prudent.[225]

3. Conclusion and Recommendation

This PFD notes that the company and Staff agree 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 pending VGP filing in Case No. U-21375.[226] Accordingly, that issue is not addressed here.

However, this PFD agrees with the company that the issue of the company's building plan for renewables to serve its VGP program can be addressed in the instant REP amendment case,[227] and this PFD also agrees with the company's representation that there is no overlap between the instant case and the company's pending VGP case regarding this specific issue.[228]

This PFD agrees with the company and recommends approval of the plan to add resources to the VGP program in the amounts of 300 MW for 2027, 500 MW for 2028, and 130 MW for 2029. The lead times involved in procuring and developing resources, such as the MISO interconnection process and lengthy business negotiations, require the company to plan several years in advance to meet future projected needs. While ABATE is correct that the 2028 and 2029 additions are not yet subscribed, that does not

[225] ABATE Reply, 4.
[226] See 3 Tr 483; 2 Tr 26-27; DTE, 48.
[227] This PFD notes that, from its testimony and briefing, it is not entirely clear what Staff's position is on this issue. Mr. Harlow provided rebuttal testimony relating to this issue, see 2 Tr 38, but Staff's brief appeared to generically suggest VGP-related issues should be addressed in a VGP proceeding without distinguishing between the VGP build plan and other VGP-related issues. See Staff, 14.
[228] Compare the instant case, Case No. U-21662, July 19, 2024, Application, p 11 (specifically requesting approval of additional solar builds for the VGP program in the instant case), with Case No. 21375, September 23, 2024, Application (failing to request any additional capacity for the VGP program).

necessarily mean that it is imprudent to expand the program considering the company's projected future demand. This PFD notes that while ABATE objects that the future additions are not yet subscribed, it does not directly challenge the company's forecast for future demand and merely criticizes the accuracy of previous forecasts. Further, this PFD has concerns that ABATE's proposal to require the company to address the 2028 and 2029 capacity buildouts in its next amended REP, which may come in mid-2027, may increase certainty regarding the level of subscription but will also come too late to allow the company to construct the resources on time to meet demand.

E. Pace of Wind Development in the REP

1. Testimony

Mr. Gold testified that the company's REP takes an ill-advised approach to wind deployment by constructing no wind generation until 2028, constructing limited wind generation from 2028 to 2034, and then building 1,000 MW of wind generation annually from 2035 onward.[229] He opined that the utility should accelerate its acquisition of wind generation.[230]

A major basis of Mr. Gold's recommendation was the results of the "reV" (Renewable Energy Potential) modeling conducted by the National Renewable Energy Laboratory (NREL) that estimated the supply curve of wind generation in MISO Zone 7, i.e. the zone covering most of Michigan's lower peninsula and coinciding with the company's service territory. He testified that, after excluding development in national forests, the modeling showed that Zone 7 had approximately 10,998 MW of developable

[229] 2 Tr 163.
[230] 2 Tr 163.

wind resources across all price points.[231] Mr. Gold explained that after excluding wind resources that have already been built in areas identified by the modelling (approximately 3,075 MW), and after excluding the most expensive 15% of wind generation in the supply curve (approximately 1,650 MW), there remained roughly 6,273 MW of readily developable wind resources in Zone 7 according to the model.[232] He explained that this value was approximately 2,500 MW less than the 8,720 MW of additional wind resources that the company planned to build by 2042 under its 2022 IRP settlement.[233]

Mr. Gold argued that the clean energy standards in 2023 PA 235 will create fierce competition for renewable resources in Michigan, and that the company will lose out on much of the available low-cost wind resources if it waits until 2035 to begin building significant amounts of wind generation.[234] He also opined that there was a risk that the company would not be able to build wind generation at the pace scheduled in its current REP because of the competition for the development of economical wind generation.[235]

Mr. Gold stated that the company could mitigate this risk by building significant amounts of wind generation sooner than currently planned or by building wind generation outside of Zone 7.[236] He suggested that earlier building of wind generation would be advantageous because the cost of wind resources was likely to increase over time.[237] Specifically, Mr. Gold recommended that the amended REP should increase wind development to 581 MW per year beginning in 2028 (to allow for development time) which

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[231] 2 Tr 166.
[232] 2 Tr 167.
[233] 2 Tr 167.
[234] 2 Tr 167-168.
[235] 2 Tr 168.
[236] 2 Tr 168.
[237] 2 Tr 169.

is the average amount needed to achieve the same level of wind development in the current REP.[238]

Mr. Jester concurred with Mr. Gold's testimony. He added that the company's IRP in Case No. U-21193, which informs its amended REP in this case, was strongly influenced by assumed build limits for renewables and that removing those artificial limits resulted in earlier and larger construction of wind resources that would reduce the company's revenue requirement.[239] Accordingly, he recommended directing the company to solicit wind resources in each round of REP procurement and to direct the company to present any beneficial wind proposals to the Commission for approval even if it would result in faster or earlier development of wind than the company proposes.[240]

In rebuttal, Mr. Harlow agreed with Mr. Gold and Mr. Jester that the company's plan induces significant risk by not including wind until 2028. He testified that the company should include wind in competitive solicitations as soon as possible to mitigate the risk that it might not be able to procure enough to meet the renewables requirements in Section 28 of PA 235.[241]

In rebuttal, Mr. Bilyeu "partially" agreed with Mr. Gold that the company could accelerate wind development, but he opined that this could be done without modifying the amended REP.[242] He explained that the build plan is flexible and the company's settlement in its 2022 IRP contemplated the acceleration of capacity above the amounts

[238] 2 Tr 169-170.
[239] 2 Tr 137-138.
[240] 2 Tr 138.
[241] 2 Tr 36.
[242] 3 Tr 305.

in the proposed course of action in that case.[243] Mr. Bilyeu added that the company's RFPs do not specify which renewable technologies must be bid in, and that the company is "renewable energy technology agnostic and will accept renewable energy projects including wind."[244] He stated that the company will consider wind projects that meet RFP requirements and will reassess its build plan in its next IRP filing in 2026.[245]

2. Briefing

The company's briefing closely tracks the points presented in Mr. Bilyeu's rebuttal testimony.[246] The company argues that Mr. Gold's "prescriptive mandate to increase the minimum pace of the deployment of wind generation in disregard of the IRP build plan should be rejected" because the implementation of the IRP and amended REP will inherently depend on the results of the competitive procurement process.[247] Further, the company emphasizes that "[u]ltimately, MEC-SC witness Jester failed to articulate a recommendation that would materially differ from how the Company approaches the competitive procurement process."[248]

Staff's brief directly quotes Mr. Harlow's testimony, which largely agreed with Mr. Gold and Mr. Jester, and Staff requests that the Commission consider the need to "actively solicit wind" in its review of the company's amended REP.[249]

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[243] 3 Tr 305, 306.
[244] 3 Tr 307.
[245] 3 Tr 307.
[246] DTE, 18-20.
[247] DTE, 19.
[248] DTE, 19.
[249] Staff, 14.

MEC-SC's brief summarizes the testimony offered by Mr. Gold and Mr. Jester.[250] It also responds to Mr. Bilyeu's rebuttal testimony stating that "[i]t is not enough for [the company] to passively accept wind bids through all-source RFPs while maintaining an imprudent and unrealistic build plan until the conclusion of an IRP case that is not expected to commence until nearly two years from now."[251] MEC-SC argues that by the time the company's next IRP case concludes in late 2027, the company will have squandered the opportunity to obtain affordable wind generation.[252] MEC-SC notes that while REPs must generally be consistent with a company's latest IRP, the Commission exempted this amended REP (the first since the enactment of PA 235) from that requirement and even directed that the company's next IRP should be consistent with this amended REP.[253] MEC-SC asserts that the settlement agreement in the company's last IRP[254] is flexible and provides that the company has the option to pursue additional capacity if there are cost effective options; MEC-SC suggests that the assumptions used in the IRP are obsolete given market conditions and changes in the law, and the amended REP should reflect these changes.[255] MEC-SC questions the company's assumption that it could add a gigawatt of wind resources per year starting in 2035 but that it could add no wind resources before 2028. MEC-SC argues that the company's 2023 all-source RFP suggests that wind resources are available, but that it "appears clear that [the company] will make no effort to procure wind before 2028 without direction from the Commission."[256]

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[250] MEC-SC, 8-13.
[251] MEC-SC, 14.
[252] MEC-SC, 14.
[253] MEC-SC, 14 (citing Case No. U-21568, Order, April 25, 2024, p 19.).
[254] Case No. U-21193
[255] MEC-SC, 15.
[256] MEC-SC, 17.

MEC-SC also addresses Mr. Bilyeu's rebuttal relating to out-of-state wind generation. MEC-SC argues that PA 235 expressly removed restrictions on out-of-state generation that previously existed in statute, but the company still categorically excludes such resources without adequate justification.[257] MEC-SC acknowledges that the company cited affordability and reliability concerns regarding resources outside of Zone 7, but MEC-SC suggested there were several flaws with these concerns and that the company was simply defaulting to an assumption in its IRP that it would not utilize out-of-state generation.[258]

In reply, the company rejoins that MEC-SC misinterprets the Commission's April 25, 2024, Order in Case No. U-21568, as creating a broad exemption from the requirement that an amended REP must reflect the assumptions included in the provider's most recently approved IRP. The company argues that the exemption applies only "to a utility whose most recently approved IRP does not reflect the renewable energy build out necessary under Act 235."[259] Because the company's most recently approved IRP reflects the necessary build out, the company maintains that its amended REP must align with the IRP. The company points out that SC agreed to, and MEC did not object to, the settlement agreement in Case No. U-21193 that endorsed the IRP renewable build plan.[260] The company also denies the assertion it is not actively soliciting wind resources, noting its renewable energy RFPs solicit wind projects as well as solar and it will actively pursue viable wind projects that meet the RFP requirements.[261] However, the company

[257] MEC-SC, 18-19.
[258] See MEC-SC, 21-23.
[259] DTE Reply, 9.
[260] DTE Reply, 9-10.
[261] DTE Reply, 8-9.

objects to mandated accelerated wind procurement because it should not "be forced to take on unsafe or unreliable projects" and stresses it received zero qualifying bids in response to 2023 RFPs.[262]

Staff did not file a reply brief.[263] MEC-SC replies that its participation in the settlement agreement in Case No. U-21193 should not prevent it from recommending updates to the 2022 IRP build plan in light of changes in the law, especially when such changes are the "whole reason for this proceeding."[264] MEC-SC disagrees with the company's claim that its current procurement strategy accommodates accelerated wind development, noting that the company has shown a preference for solar and that "[w]aiting for wind projects to drop into DTE's lap is not an adequate wind procurement strategy."[265] MEC-SC's reply also addresses the exclusion of out-of-state wind, which MEC-SC describes as unreasonable, imprudent, and not based on substantial evidence. MEC-SC reiterates its argument that the Commission's order allows the amended REP to vary from assumptions in the IRP and adds that the settlement agreement does not approve or otherwise provide support for the exclusion of out-of-state resources.[266]

MEC-SC requests that the Commission condition its approval of the amended REP on the company agreeing to add wind generation before 2028, to increase the amount of wind generation to be added from 2028 to 2034, and to expand RFPs to include out-of-

[262] DTE Reply, 10.
[263] See Staff letter filed January 31, 2025.
[264] MEC-SC Reply, 17.
[265] MEC-SC Reply, 18.
[266] MEC-SC Reply, 18-21.

state renewable energy resources. MEC-SC also request that the Commission direct the company to explore ways to attract new wind projects.[267]

3. Conclusion and Recommendation

This PFD agrees with MEC-SC's interpretation of the Commission's April 25, 2024, Order in Case No. U-21568, which clearly stated that the initial amended REP after PA 235 "may not align with the most recent approved IRP." [268] The Commission recognized that "the most recently approved IRP may not reflect the renewable energy build out necessary under Act 235" and provided that "the initially filed amended REP should reflect the utility's plans to comply with Act 235."[269] While the company maintains its most recently approved IRP reflects the renewable energy build out necessary under Act 235, the company did not consider the effect of PA 235 on the availability or cost of wind resources. Indeed, the company could not have considered the attendant effects of PA 235 in its 2022 IRP. MEC-SC presented a credible argument, with which Staff agrees, that the pacing of company's build plan does not reflect a reasonable renewable energy build out required under PA 235 because of the risk of delaying wind development when readily obtainable and cost-effective wind resources are limited in MISO Zone 7. Therefore, this PFD agrees with MEC-SC and Staff that the Commission should recommend the company proactively accelerate wind development as part of its amended REP.

[267] MEC-SC Reply, 18-19.
[268] April 25, 2024, Order in Case No. U-21568, p 19-20.
[269] April 25, 2024, Order in Case No. U-21568, p 20.

This PFD also agrees with MEC-SC's position that out-of-state wind resources are allowed as a result of PA 235 amending MCL 460.1029[270] and should be considered and included in future RFPs for renewable energy resources. While there may be valid reasons to choose in-state projects instead of out-of-state projects, the company should explore all available options and consider them on their individual merits; the company should not categorically exclude out-of-state resources. Therefore, for the reasons discussed above as well as for the reasons more fully articulated in Subsection G of this PFD addressing RFPs, *infra*, this PFD proposes that the Commission also recommend that out-of-state resources be included for consideration in future RFPs.

However, this PFD does not agree with MEC-SC witness Gold's recommendation to mandate wind development of 581 MW per year beginning in 2028. There is simply not enough evidence in the record to determine whether this is a reasonable target to set, and such specific development targets are better examined holistically in IRP proceedings as recognized in the Commission's April 25, 2024 Order.[271] This PFD believes that the Commission should affirmatively state that it expects the company to make a meaningful, good faith effort to proactively accelerate its wind development timetable, including through the consideration of out-of-state wind resources, but should not require a specific threshold to be met.

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[270] See MCL 460.1029(1)(b).
[271] April 25, 2024, Order in Case No. U-21568, p 19 ("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[.]").

F. Calculation of Incentive RECs

1. Testimony

Mr. Bilyeu provided a projection of the RECs that the company would either self-generate or receive from third party renewable energy systems, including a forecast of incentive RECs under MCL 460.1039(2).[272]

Mr. Jester testified that the company calculated its incentive RECs under MCL 460.1039(2) appropriately, with two exceptions:

First, he opined that the company did not appropriately calculate incentive RECs under MCL 460.1039(2)(b) for "electricity generated from a renewable energy system, other than wind, at peak demand time, as determined by the commission." Mr. Jester testified that the definition of peak demand time adopted by the Commission, which uses peak hours defined by MISO, is "outdated and the Commission should reconsider it."[273] Mr. Jester stated that high demand is no longer the principal determinant of the need for incremental capacity because wind and solar are variable, and he asserted that MISO is "increasingly focused on resource contributions during 'tight hours' when the net availability of resources does not exceed demand by a large margin."[274] He also asserted that the definition of peak hours used by MISO is inconsistent with the on-peak hours used in the company's rate book for various customer types.[275] Mr. Jester proposed redefining peak demand time as follows:

> I recommend that the Commission base its definition of "peak demand time" on the times when non-wind renewable resources provide capacity value as accredited by MISO. These are currently the hours ending 15, 16, & 17

[272] See 3 Tr 291; see also Exhibit A-4 (detailing the company's REC projections).
[273] 2 Tr 140.
[274] 2 Tr 140.
[275] 2 Tr 140-141.

> for Summer, Fall, and Spring, and hours ending 8, 9, 19, & 20 for Winter. According to FERC's decision in Docket No. ER24-1638, issued on October 25, 2024, MISO will transition to a new capacity accreditation methodology, which will evaluate resources' performance under a differently identified set of system risk hours, beginning with the 2028-2029 planning year. When MISO develops this new approach, the Commission should adapt to that methodology.[276]

Second, Mr. Jester asserted that the company did not appropriately calculate incentive RECs under MCL 460.1039(2)(c) for "electricity generated from a renewable energy system during off-peak hours, stored using an energy storage system or a hydroelectric pumped storage facility, and used during peak hours." He explained that the company's calculation was problematic because it was informed by the MISO definition of peak hours, which was not apt for the reasons previously described above.[277] He also opined that the calculation used, which relied on the method adopted by the Commission in its December 4, 2008, order in Case No. U-15800, was "equivalent to assuming that when Ludington Pumped Storage Plant is pumping, all available renewable generation up to the amount needed for pumping is used for that pumping. This is inconsistent with how the power system currently operates."[278] Mr. Jester explained that when Ludington pumps water to charge its system, that incremental load will be served by the next resource in the economic dispatch sequence, "and as such is not served by renewables unless renewable generation is so high relative to load at that time that renewable generation is curtailed."[279] He asserted that if renewables are not on the margin of economic dispatch, then pumping would be powered by incremental dispatch of fueled

[276] 2 Tr 141.
[277] 2 Tr 142.
[278] 2 Tr 142.
[279] 2 Tr 143.

resources like nuclear or natural gas, and it would be unreasonable to assume that all renewable generation would be preferentially used for pumping for the purpose of calculating RECs.[280] Mr. Jester recommended that "[t]he Commission should deem that electricity generated from a renewable energy system during off-peak hours is stored using an energy storage system or hydroelectric pumped storage facility only when renewable resources are marginal in merit-order dispatch and would have been curtailed in the absence of charging a storage resource."[281] He explained that based upon his review of MISO operation reports, no storage facility would experience renewables as a marginal resource with any material frequency, at least not at the present time, although that may change in the 2030s as utilities build more renewable generation.[282]

Mr. Jester testified that the number of incentive RECs would be "materially reduced" if the company were to recalculate them according to his two recommendations, but he added that even eliminating these two categories of RECs would not render the company's plan non-compliant with the standards in 2023 PA 235.[283]

In rebuttal, Mr. Bilyeu rejected the notion that the definition of peak demand time was inappropriate because the company utilized the definition that the Commission previously adopted.[284] He also opined that the company's amended REP proceeding was not the appropriate forum to address proposed changes to the definition of peak demand time for the purpose of calculating RECs because it would have broad

[280] 2 Tr 143.
[281] 2 Tr 143.
[282] 2 Tr 143.
[283] 2 Tr 144, 145.
[284] 3 Tr 308.

implications for all regulated utilities.[285] Mr. Bilyeu also rejected Mr. Jester's proposal regarding the calculation of RECs related to pumped storage. He explained that the methodology used by the company was previously approved by the Commission in Case No. U-15800.[286] He further rejected Mr. Jester's recommendation explaining:

> Suggesting that any individual or incremental load on the MISO system (including for charging an energy storage system) is exclusively served by the marginal resource within MISO is incorrect. Further, MISO determines the marginal resource based on its model (the MISO Monthly Operations Reports referenced by Witness Jester provides MISO-wide marginal resource results) but does not (and cannot) track the individual electrons that flow from resources to load (or storage systems).[287]

Mr. Harlow's rebuttal rejected the contention that the definition of peak demand time was outdated because the company used the Commission's definition, which was based upon the MISO definition. He added that while there are discussions about updating the definition within MISO, it would be premature to update the current definition.[288] Mr. Harlow added that it would be inappropriate to update the definition without the input of all affected utilities. He recommended that if the Commission wanted to consider an update, then it should be done in the context of a workgroup.[289]

2. Briefing

The company concurs with the points made in Staff witness Harlow's rebuttal testimony, and the company also maintains that this amended REP proceeding is not the appropriate forum for addressing the definitional change of peak demand time suggested

[285] 3 Tr 308.
[286] 3 Tr 309.
[287] 3 Tr 309-310.
[288] 2 Tr 36.
[289] 3 Tr 36.

by Mr. Jester.[290] The company further repeats the points made by Mr. Bilyeu in his rebuttal testimony regarding the calculation of RECs related to pumped storage.[291]

Staff reiterates that it is premature to redefine peak demand for the reasons stated in Mr. Harlow's testimony, and Staff recommends that the Commission decline to update the definition in this case. In any event, Staff recommends that any change to the definition should be reserved for a workgroup (possibly in the transfer price workgroup suggested in response to proposals to change transfer price methodology) rather than decided in the instant case.[292]

MEC-SC acknowledges that the company used the definition of peak demand that the Commission adopted 16 years ago in its temporary order in Case No. U-15800, but it argues that this does not prohibit reconsideration of the peak demand time for RECs now.[293] MEC-SC asserts that in cross-examination, Mr. Harlow even agreed that the definition should be revisited, albeit suggesting that an update should be done via a discussion in a workgroup.[294] MEC-SC further contends that there are five reasons to redefine peak demand time for incentive RECs now: (1) the temporary order in Case No. U-15800 is 16 years old, and in directing the Commission to issue a temporary order the Legislature did not intend for such an order to remain in effect for more than a year; (2) the temporary order does not actually indicate that the Commission "relied" on MISO in deciding what definition to use and merely stated that it was "consistent with" the then-current MISO definition; (3) the definition in the temporary order is not actually consistent

[290] DTE, 21.
[291] DTE, 22.
[292] Staff, 20.
[293] MEC-SC, 34.
[294] MEC-SC, 36, 37 (citing 2 Tr 35-36 and 2 Tr 100)

with the current MISO tariff definition because the two differ; (4) “peak demand time” for the purposes of incentive RECs should not be the same as “on peak” because they are different, and the current definition incentivizes solar generation beyond that which adds capacity value at times when demand is highest; and (5) the Commission can establish precedent in a contested case so there is no need to convene a workgroup.[295]

MEC-SC also addressed the calculation of incentive RECs for pumped storage by repeating key points from Mr. Jester’s testimony.[296] MEC-SC argues that statements made by Mr. Bilyeu during cross-examination largely confirmed Mr. Jester’s premise that the current method for calculating incentive RECs for pumped storage does not represent the way in which renewable energy is used to fill the reservoir at Ludington.[297] MEC-SC argues against Mr. Bilyeu’s testimony relating to inability to track the flow of electrons stating that “[o]ne does not need to identify specific electrons—one needs to know what resource is being dispatched to [sic] when system load goes up to power Ludington.”[298]

The company replies that MEC-SC’s proposed definition of peak demand time should not be adopted in this proceeding, there is no statutory mechanism in amended REP cases for an intervenor to advocate for revising such a definition, and it is not a contested issue under PA 235 that the Commission is tasked with deciding in amended REPs.[299] The company argues that peak demand time for incentive RECs has been previously defined by the Commission in Case No. U-15800 and has been reaffirmed in subsequent orders. The company also asserts that the current MISO definition of “on

[295] See MEC-SC, 37-40.
[296] See MEC-SC, 41-44.
[297] MEC-SC, 45-47.
[298] MEC-SC, 45.
[299] DTE Reply, 11-12.

peak" is found in Exhibit MEC-16 and is consistent with the Temporary Order in Case No. U-15800.[300]

The company also maintains its disagreement with the proposed change to calculating incentive RECs for Ludington because the company used the approved method from Case No. U-15800 and MEC-SC's proposed alternative erroneously assumes that any incremental load on the MISO system is exclusively served by the marginal resource within MISO.[301] The company also contends that just because Ludington turns on to pump, it does not necessarily mean that additional generation is turned on as well if there is enough on the grid to support Ludington.[302]

MEC-SC rejoins that the company and Staff have not provided reasons that are sufficient to support the continuation of a definition of peak demand time from a 16-year-old temporary order that over-incentivizes solar by awarding incentive RECs for virtually every weekday hour that solar assets are generating.[303] MEC-SC argues that even Mr. Harlow essentially agreed that the current definition over-incentivizes solar and could stand revision.[304] MEC-SC's reply notes that, regarding incentive RECs for pumped storage, its initial brief anticipated and addressed the company's arguments.

3. Conclusion and Recommendation

This PFD initially notes that the company's incentive REC calculations are not inappropriate per se because the company relied upon the methodology established by the Commission in its Temporary Order in Case No. U-15800. Instead, the gravamen of

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[300] DTE Reply, 12.
[301] DTE Reply, 14.
[302] DTE Reply, 14.
[303] MEC-SC Reply, 26.
[304] MEC-SC, 26.

MEC-SC's argument is that the methodologies laid out in Case No. U-15800 for calculating certain incentive RECs should be revised.

Regarding the definition of "peak demand time" for incentive RECs under MCL 460.1039(2)(b), this PFD agrees with MEC-SC that the definition could stand to be revised. As MEC-SC has argued, the definition of "peak demand time" for incentive RECs first set more than a decade ago in a temporary order may no longer be suitable today, and indeed, the current definition appears to have the effect of over-incentivizing solar generation for the reasons stated by MEC-SC. This PFD also notes that during cross-examination, Mr. Harlow agreed that it is likely worthwhile to revisit the definition of "peak demand time" for the purposes of incentive RECs because of the wide disparity between MISO critical hours for intermittent generation and the current definition adopted in the Commission's temporary order.[305]

This PFD disagrees with MEC-SC, however, regarding how the definition of peak demand time should be revisited. This PFD agrees with Staff that any consideration of an update to the definition of peak demand time for incentive RECs should be done in the context of a workgroup or conference so that other affected utilities and interested parties can provide input. Accordingly, this PFD recommends that the issue of updating the definition of "peak demand time" for the purpose of incentive RECs should be added to the workgroup or conference addressing the transfer price which was recommended in section B *supra*.

[305] See 2 Tr 100.

Regarding the method of calculating incentive RECs under MCL 460.1039(2)(c) for pumped storage, this PFD acknowledges that the current methodology is arguably imperfect as noted by MEC-SC, and it is not unreasonable for MEC-SC to propose using a different methodology that looks to the marginal resource dispatched to serve the incremental load when Ludington's pumps are activated. However, this PFD also agrees with the company that MEC-SC's proposed method is not without flaws itself because it is not necessarily true that any incremental load on the MISO system is exclusively served by the marginal resource within MISO. Accordingly, while this PFD does not view MEC-SC's recommendation as unreasonable, it nevertheless declines to recommend updating the current methodology for calculating these incentive RECs related to pumped storage. If the Commission were inclined to revisit this issue, then this PFD would recommend adding this issue to the same workgroup or conference addressing peak demand time and the transfer price.

G. Updates to Request for Proposal (RFP) Criteria

1. Testimony

Mr. Bilyeu described the company's competitive bidding process for RFPs and how it is designed to comply with past Commission orders regarding procurement as well as the company's IRP settlement in Case No. U-21193.[306]

Mr. Jester acknowledged that the company compared proposals using economic criteria including a comparison of the levelized cost of renewable energy, but he testified that the economic criteria used in the company's evaluation of proposals needs to be

[306] 3 Tr 297-299.

revised. He explained that after the adoption of 2023 PA 235, renewable resources included in the company's REP can be located anywhere within MISO.[307] He argued that the company should therefore allow proposals from outside of MISO Zone 7 and outside of Michigan, "but all proposals should be evaluated on the difference between levelized cost of energy and the expected basis differences of both energy and capacity in the resource location vs [the company]'s service territory."[308]

Mr. Jester also asserted that aside from locational issues, the levelized cost of energy does not capture other important aspects of grid economics. He explained:

> Myriad resource design details such as wind turbine hub height and blade design, solar tracking, inverter to panel ratios, bifacial vs unifacial panels, and etc. affect the ratios of energy output and capacity credits. They also affect capacity credits differently in the different seasons under MISO's recently adopted seasonal resource adequacy standards. These factors can also be addressed in [the company]'s resource selection process if the principal economic criterion is the difference between levelized cost of the resource and the expected values of energy and capacity based on the proposed design.[309]

Mr. Jester recommended that the Commission direct the company to propose a modified selection process in its next REP amendment that accounts for these considerations.[310]

In rebuttal, Mr. Bilyeu rejected the suggestion to include the various factors listed by Mr. Jester above. He explained that the company already requires key attributes and design considerations to be provided by the project developer and likewise requires a generation profile for the specific proposed resource.[311] He stated that these data elements are "key inputs to the economic evaluation of individual renewable projects" and

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[307] 2 Tr 153.
[308] 2 Tr 155.
[309] 2 Tr 155.
[310] 2 Tr 156.
[311] 3 Tr 315.

that no changes are necessary because such details are already incorporated into the company's selection criteria.[312]

Mr. Bilyeu also rejected the proposal to allow resources from outside of Zone 7 or outside of Michigan. Aside from job creation and tax benefits from in-state development, he asserted that there are affordability and reliability risks associated with reliance on resources outside of Zone 7.[313] Mr. Bilyeu highlighted that Mr. Jester was correct to admit that capacity credits in a zone other than Zone 7 are less useful than credits within Zone 7.[314] He testified that the company's customers "are exposed to the potential of additional capacity costs whenever resources outside of Zone 7 are used to meet the Company's resource adequacy requirements."[315] Further, he stated that due to Michigan's peninsular geography, Zone 7 has on average required 94.5% of resources used to meet the planning resource margin requirement to be physically located within Zone 7.[316]

2. Briefing

The company's brief largely mirrors and repeats the direct and rebuttal testimony of Mr. Bilyeu.[317] The company emphasizes that no changes are necessary to the company's RFP selection criteria because Mr. Jester's suggested additions to the criteria are already incorporated into the key attributes and design considerations that the company specifies as part of the RFP process.[318] The company further emphasizes that, per Commission order, the Amended REP's build plan must align with the company's

[312] 3 Tr 315.
[313] 3 Tr 316.
[314] 3 Tr 316.
[315] 3 Tr 316.
[316] 3 Tr 316-317.
[317] See generally DTE, 40-46.
[318] DTE, 43.

approved IRP in Case No. U-21193, which assumed that all future renewable generation would be built within Michigan.[319] The company argues that MEC-SEC is "attempting to get a second bite of the apple" by challenging an already settled issue decided in the IRP process, and this challenge would undermine "the fundamental interplay between IRPs and REPs established in the April 25 Order[320] and set forth in Act 235."[321]

MEC-SC's brief emphasizes that PA 235 removed a previous restriction on using out-of-state resources and now expressly approves of using out-of-state resources to meet RES goals under certain conditions.[322] MEC-SC contends that the company did not justify its decision to exclude out-of-state resources in the company's direct case and notes that, in another case, peer utility Consumers Energy offered testimony from one of its witnesses explaining that it is willing to procure out-of-state resources as part of its REP.[323] MEC-SC asserts that the company offered no details to support its claim about the incidental benefits of in-state development (i.e. job creation, tax revenue, etc.), and MEC-SC acknowledges that the company cited affordability and reliability concerns regarding resources outside of Zone 7, but MEC-SC suggested there were several flaws with these concerns and that the company was simply defaulting to an assumption in its IRP that it would not utilize out-of-state generation.[324]

The company rejoins that MEC-SC's recommendation ignores the settlement agreement in the company's most recent IRP in Case No. U-21193 that agreed to exclude

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[319] DTE, 43.
[320] This refers to the Commission's April 25, 2024, Order in Case No. U-21568, which established filing requirements for amended REPs.
[321] DTE, 44.
[322] MEC-SC, 19 (citing MCL 460.1029(1)).
[323] MEC-SC, 19-10 (citing testimony in Case No. U-21816).
[324] See MEC-SC, 21-23.

resources outside of Michigan and that the Commission's April 25 Order stated that amended REPs should reflect the assumptions in the providers' most recently approved IRP.[325] The company requests that the Commission ignore MEC-SC's reference to testimony in Consumers Energy's REP as irrelevant and that, for various reasons, it would be prejudicial and improper to consider the testimony of another utility's witness in this case.[326] The company asserts that evaluations related to incremental increase in risk exposure caused by resources outside of Zone 7 was addressed in its IRP, Case No. U-21193, through company witness Burgdorf's testimony.[327] The company asserts that it properly relied on company witness Hernandez's testimony in Case No. U-21193 which confirmed that the renewable build plan assumed that no out-of-state assets would be included, and thus the company included that assumption from the IRP.[328] The company rejected MEC-SC's criticism of the company's demonstration of Zone 7's effective capacity import limit and further cast doubt on MEC-SC's citation to Staff's capacity demonstration report in Case No. U-21393 because Staff's report held some data constant while the company used projections for specific planning years.[329] The company contends that it should evaluate its build plan in its next IRP in December 2026 and that its next IRP is the appropriate venue to reconsider resource procurement from outside of Miso Zone 7.[330]

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[325] DTE Reply, 28.
[326] DTE Reply, 29.
[327] DTE Reply, 30.
[328] DTE Reply, 30.
[329] DTE Reply, 31.
[330] DTE Reply, 31.

3. Conclusion and Recommendation

This PFD agrees with the company that it need not update its RFP process to include the various specific resource design details listed by Mr. Jester because such attributes can be or already are incorporated into the key attributes and design considerations that the company specifies as part of its RFP process.

However, as was discussed in subsection E of this PFD regarding the pace of wind development, *supra*, this PFD recommends that RFPs be updated to allow out-of-state resources to be considered as is now allowed by MCL 460.1029(1)(b).[331] The company asserts that it relied on the assumption in its last IRP that no out-of-state renewables would be pursued, and that this reliance is consistent with the Commission's direction in its April 25, 2024, Order stating that amended REPs should reflect assumptions included in the most recently approved IRP. However, the Commission's Order exempted the current round of amended REPs, i.e. the first filed after the passage of PA 235, from aligning with previous IRPs to allow updates to accommodate PA 235. The Commission's Order stated:

> The Commission agrees with several comments 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 (including the consideration of the value of the various resource types and attributes as expressed by commenters). **In turn, future amended REPs should reflect the assumptions included in the providers' most recently approved IRP; however, the initial amended REP filed pursuant to the schedule set in this docket may not align with the most recently approved IRP.** The Commission recognizes that for the initial round of amended REPs pursuant to Act 235, the most recently approved IRP may not reflect the renewable energy build out necessary under Act 235. **Therefore**, **the initially filed amended REP**

[331] This PFD notes that it agrees with the company that MEC-SC's reference to the plans of peer utility Consumers Energy is not apt. Accordingly, this PFD disregards MEC-SC's argument to the extent that it compares the company's stance with that of a witness from Consumers Energy in a different proceeding.

> **should reflect the utility's plans to comply with Act 235.** Conversely, a future IRP should also reflect the providers' approved amended REP.[332]

As the emphasized portion of the Commission's order states, while it is generally true that amended REPs should reflect the assumptions included in a provider's previous IRP, the Commission exempted this specific amended REP proceeding from that guidance to allow revisions to accommodate PA 235. This PFD does not read the Commission's Order with the same degree of restrictiveness as the company.[333] Accordingly, this PFD suggests that the company is not bound by an assumption it made in its last IRP, i.e. that no out-of-state resources will be procured, when PA 235 specifically amended MCL 460.1029(1) to allow out-of-state resources to be used to generate RECs when that practice was previously restricted.[334] Simply put, the change in the law brought about by PA 235 undercuts legal support for the previous assumption.

This PFD recognizes that the company put forward several substantive reasons to assume that in-state resources may be preferable to out-of-state resources, most of which relate to affordability and reliability concerns regarding resources outside of Zone 7. This PFD acknowledges that these concerns have legitimacy. However, the company should not categorically exclude out-of-state resources when a change in the law has occurred

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[332] Case No. U-21568, April 25, 2024, Order, p 19-20 (emphasis added).
[333] The company argues that the exemption applies only to a utility whose most recently approved IRP does not reflect the renewable energy build out necessary under Act 235, and that the company's IRP already reflected the necessary buildout such that the exemption does not apply. This PFD recognizes that the Commission's reasoning for the exemption stated that a previous IRP may not reflect the renewable energy build out necessary under Act 235. But the Commission's specific statement concerning the exemption was more general in nature: that the amended REP "should reflect the utility's plans to comply with Act 235." This PFD submits that if an assumption from a previous IRP is no longer reasonable or supportable because of a change in law brought about by PA 235, then updating that assumption in the amended REP can bring it into alignment or compliance with PA 235.
[334] Compare current MCL 460.1029 as amended by 2023 PA 235 (broadly allowing out-of-state renewables to be used to generate RECs) with former MCL 460.1029 as amended by 2016 PA 342 (restricting the use of out-of-state renewables to generate RECs with narrow, limited exceptions).

that makes their use possible under a much wider array of circumstances than was permitted under the previous, heavily restrictive statutory scheme. Instead, this PFD suggests that the company should update its RFP requirements to allow the exploration of all available options, both inside and outside of MISO Zone 7, and evaluate them on their individual merits.

H. Standing Offer Contracts

1. Testimony

Mr. Jester explained that he supports competitive bidding, but it tends to favor larger projects that can better absorb the transaction costs as well as projects without additional complexity.[335] He therefore recommended that the Commission and the company allow the use of standard-offer contracts in which small projects can be developed without participating in the competitive bidding process.[336] He added that such contracts could be for build-and-transfer agreements as well as for power purchase agreements (PPAs).[337] Mr. Jester did not recommend that these contracts be made pursuant to the Public Utilities Regulatory Policies Act (PURPA). Instead, he recommended that they be made under MCL 460.1028(6), which states in pertinent part that "[t]he commission shall not approve a contract based on an unsolicited proposal unless the commission determines that the unsolicited proposal provides opportunities that may not otherwise be available or commercially practical through a competitive bid process."[338] He suggested that the company should make standard-offer contracts

[335] 2 Tr 157.
[336] 2 Tr 157.
[337] 2 Tr 157.
[338] 2 Tr 158.

available for projects under 5 MW in size that would be located in settled areas with small parcel sizes, on brownfields, and for agrivoltaics projects because these project types are unlikely to be available or commercially practical in a competitive bidding process.[339] Mr. Jester opined that the prices for these standard-offer contracts should be periodically adjusted based on the outcome of the company's competitive bidding process but adjusted by a line loss factor.[340]

In rebuttal, Mr. Bilyeu rejected this proposal and explained that the company already offers multiple pathways for small projects to sell power to the company. Mr. Bilyeu testified that the company is already obligated to purchase power from qualifying facilities under PURPA through Rider 5, which allows such projects to bypass competitive bidding.[341] Mr. Bilyeu testified that Rider 5 already offers a price based upon the competitive bidding process results that are updated annually such that it aligns with Mr. Jester's recommendation for standard-offer contract pricing.[342] He also testified that the company issues annual RFPs where small solar and wind projects can participate. He contended that Mr. Jester's recommendation would be duplicative of these efforts.[343]

2. Briefing

The company did not provide a discussion of this issue in its initial brief, but MEC-SC's brief tracks Mr. Jester's testimony and Mr. Bilyeu's rebuttal.[344] MEC-SC argues that its proposal is not duplicative with a project under Rider 5 because the company currently

[339] 2 Tr 158.
[340] 2 Tr 158.
[341] 3 Tr 318.
[342] 3 Tr 319.
[343] 3 Tr 318.
[344] MEC-SC, 47-50.

has no need for capacity under PURPA so that no such projects would receive compensation for capacity, only energy based upon locational marginal prices (LMPs). MEC-SC contends that current LMP forecasts range from $34.80 per MWh off-peak and $50.67 per MWh on-peak in 2025 to $63.84 per MWh off-peak and $67.54 per MWh on-peak in 2029. By contrast, MEC-SC asserts that PPAs have LCOEs ranging from $82-$85 per MWH after adjustments.[345] MEC-SC asserted that its proposal would support uniquely beneficial projects that would not be supported under Rider 5 and that would not otherwise be commercially viable under the RFP process.[346]

The company rejoins that "by 2029 the LMP would pay more than the forecasted LCOE in the Amended REP."[347] The company concludes that "PURPA, even without capacity, is a better deal than MEC-SC's proposed Standard Offer Contract that is based on the average LCOE received in RFPs."[348] MEC-SC's reply did not provide further argument on this issue.

3. Conclusion and Recommendation

This PFD generally agrees with the company that existing structures, including PURPA/Rider 5, as well as the company's annual RFP process, already offer acceptable opportunities for small projects to be considered. Accordingly, this PFD does not see a pressing need for a new mechanism to promote the construction of small projects and does not recommend the creation of standing offer contracts.

[345] MEC-SC, 51.
[346] MEC-SC, 51-52.
[347] DTE Reply, 40.
[348] DTE Reply, 40.

I. REC-only Contracts

1. Testimony

Mr. Gold testified that the company's plan showed that from 2024 through 2045, it planned to purchase over 17.24 million RECs through REC-only contracts at a cost of $82.9 million, or approximately $4.81/REC.[349] He explained that this price was a 7-fold increase from the cost per REC when purchased through a PPA contract, where the average cost is only $0.73/REC.[350] Mr. Gold argued that the value of these REC-only contracts was "unclear" because, according to the company's own accounting, it does not need to purchase any REC-only contracts to comply with renewable energy standards in PA 235 in any year from the present to 2045.[351] Mr. Gold also explained that Section 28(5)(c) of PA 235 states that RECs cannot be used to meet renewable energy standards after 2035.[352] Mr. Gold asserted that REC-only contracts are expensive and unnecessary in years between 2024 and 2035, and that they are effectively useless for compliance purposes after 2035.[353] He recommended that REC-only contracts should only be allowed if all other avenues of compliance with renewable standards are exhausted and that they should not be purchased preemptively, but only in response to a short-term risk of non-compliance.[354]

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[349] 2 Tr 170.
[350] 2 Tr 170.
[351] 2 Tr 170-171.
[352] 2 Tr 171.
[353] 2 Tr 172.
[354] 2 Tr 172.

Mr. Kenworthy testified that REC-only contracts offer flexibility and can serve as a short-term solution, but he asserted that the company "should seek to reduce reliance on REC-only contracts in favor of direct generation sources as soon as feasible."[355]

In rebuttal, Mr. Bilyeu acknowledged that the company's forecast shows that it will not need to use REC-only contracts for compliance purposes as currently projected.[356] However, he explained that the amended REP includes a forecast of RECs from assets that have not yet been built and from PPAs that have not yet been fulfilled, and various risks could affect the company's ability to meet higher renewable portfolio standards.[357] Mr. Bilyeu testified that it was "important for [the company] to retain the option of using REC-only contracts as a hedge against those risks."[358] He added that the inclusion of REC-only contracts in the amended REP does not obligate the company to enter into such contracts, is intended to maintain flexibility, and their inclusion has a minimal impact on the overall cost of the amended REP.[359]

2. Briefing

In its brief, the company repeats the arguments presented in Mr. Bilyeu's rebuttal testimony and argues that MCL 460.1028(5)(c) provides that the company can use REC-only contracts to comply with up to 5% of the requirements under the renewable energy standard.[360] The company suggests that the Commission should reject Mr. Gold's proposal to disallow use of REC-only contracts as inconsistent with law, and the company

[355] 3 Tr 609.
[356] 3 Tr 310.
[357] 3 Tr 310.
[358] 3 Tr 310.
[359] 3 Tr 311.
[360] DTE, 17.

maintains that its amended REP reasonably includes the option to use REC-only contracts and that the acquisition of REC-only contracts will be subject to review in REP reconciliation proceedings.[361]

MEC-SC repeats the testimony of Mr. Gold and critiques Mr. Bilyeu's rebuttal for failing to address the high cost of REC-only contracts and their lack of utility after 2035.[362] MEC-SC argues that REC-only contracts would not be reasonable and prudent unless no other avenue for compliance existed and that the Commission should direct the company to remove REC-only contracts after 2035 and find that REC-only contracts from 2024 through 2035 are excessive, unreasonable, and unlikely to be approved in reconciliation proceedings.[363]

CEO acknowledges that REC-only contracts are a relatively small part of the company's compliance strategy, but they argue that such contracts provide no lasting value whereas building renewables will continue to deliver benefits into the future. Accordingly, CEO argues that the Commission should provide guidance to the company regarding the need to minimize reliance on REC-only contracts in future cases to enhance long-term stability.[364]

The company replies that "[w]ithout the inclusion of REC-only contracts in the Amended REP, any purchased RECs might be considered non-compliant and therefore must be included to ensure the Company's legal right to purchase is upheld."[365] The company argues that as applied to REC-only contracts in 2024-2035, MEC-SC's request

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[361] DTE, 18.
[362] MEC-SC, 33.
[363] MEC-SC, 33.
[364] CEO, 4.
[365] DTE Reply, 6.

is essentially that the Commission "should issue something akin to a Section 7 warning under Act 304 of 1982, MCL 460.6j(7), to warn the Company that recovery of costs related to REC-only contracts is unlikely to be approved in REP reconciliation proceedings."[366] But the company argues that PA 235 does not provide for such a warning in REP plans or reconciliations such that the Commission "should be circumspect about issuing such warnings in amended REP proceedings."[367] The company maintains that it has the statutory right to purchase REC-only contracts under MCL 460.1028(5)(c) and that Mr. Gold's estimate that the cost per REC under REC-only contracts is seven times as expensive as RECs obtained from PPAs is flawed because he "erroneously assumes that the capacity and energy would be at exactly the transfer price."[368]

MEC-SC emphasizes that Mr. Gold only recommends that REC-only contracts should be limited to circumstances where all other avenues for compliance with the RES are exhausted. MEC-SC asserts that MCL 460.1028(5) provides permissible options for obtaining RECs but does not give the company a "right" to use REC-only contracts; instead, MEC-SC contends that the company's proposed REC-only contracts would run afoul of MCL 460.1022(5) and (6) which require an amended REP and the projected costs therein to be reasonable and prudent.[369] MEC-SC rejects the notion that it is reasonable to include the contracts for flexibility or to hedge against risk that can be evaluated in future reconciliation proceedings because MCL 460.1022(5) and (6) require the Commission to evaluate amended REPs and projected costs in this proceeding.[370]

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[366] DTE Reply, 6.
[367] DTE Reply, 7.
[368] DTE Reply, 7.
[369] MEC-SC Reply, 22.
[370] MEC-SC, 23.

3. Conclusion and Recommendation

This PFD notes that MCL 460.1028(5)(c) plainly states that RECs derived from REC-only contracts cannot be used to comply with the RES after 2035. Accordingly, this PFD agrees with MEC-SC that any REC-only contract after 2035 should be removed from the amended REP because it would no longer have any utility for compliance purposes.

For REC-only contracts from 2024 through 2035, this PFD agrees with the company that it is reasonable and prudent to include them in the amended REP to provide flexibility to use such contracts if needed for compliance purposes. As the company has stated, their inclusion in the amended REP does not obligate the company to enter into such contracts and provides a hedge against the risk of noncompliance if other sources of RECs do not materialize.

However, this PFD also agrees with CEO and MEC-SC that RECs from generating resources are preferable and that REC-only contracts should generally be considered a compliance option of last resort given their expense and lack of utility after 2035. Further, while it has not stated as much, the company appears to tacitly agree with that sentiment because it emphasized that it is not obligated to enter into REC-only contracts and that such contracts are included in the amended REP to maintain flexibility and hedge against the risk of noncompliance.

This PFD disagrees with MEC-SC and does not believe that the Commission should warn the company that REC-only contracts from 2024 through 2035 are unlikely to be approved in reconciliation proceedings because PA 235 provides no explicit statutory warning mechanism. Further, circumstances may arise wherein use of REC-only contracts could be a reasonable compliance strategy. Instead, the Commission

should simply take this opportunity to remind the company that any decision to utilize REC-only contracts will be closely reviewed and scrutinized in reconciliation proceedings.

J. Sensitivity for High Load Growth

1. Testimony

Ms. Glick suggested that data centers and other sources of load could substantially increase the company's compliance obligations under new renewable energy standards beyond what is currently projected. She testified that in late 2024, the Michigan Legislature was considering bills that would create tax incentives for large data centers.[371] She also testified that the company apparently foresaw large data centers as a potential source of new load because the company filed an ex-parte application to create an XL high load factor rate factor citing the potential of data centers as an emergent customer type.[372] Ms. Glick asserted that the growth in large load customers is a relatively recent trend for utilities across the country, and it is important for utilities to incorporate a sensitivity for high load projections into their REP applications where there are clear changes in the market relative to prior IRP filings.[373]

Ms. Glick asserted that the company's REP did not evaluate how its RES compliance would change with higher load growth as could be expected from data center load. Ms. Glick testified that using the company's higher load forecast from its 2022 IRP, the company's compliance obligations would increase such that it needed to rely on banked RECs to meet compliance obligations in 2031, 2032, and 2035.[374] She further

[371] 2 Tr 188-189.
[372] 2 Tr 189 (quoting Case No. U-21163, May 21, 2024, Ex-Parte Application, p 2).
[373] 2 Tr 190, 191.
[374] 2 Tr 193.

testified that, using another high load growth model in line with data center growth, the company would no longer have enough RECs to comply with renewable energy standards in the early to mid-2030s.[375] Indeed, Ms. Glick testified that if the compound annual growth rate increases to 2.5% or 3% as could be anticipated from data center growth, then the company's REC bank is depleted in the 2030s and the planned renewable buildout is insufficient to comply with renewable energy standards.[376]

Ms. Glick recommended that the company "should include a high load sensitivity in its current and all future REP applications. For the REP application, the high load forecast can mirror a high load growth scenario from the IRP, with any relevant changes to the market since the IRP was filed (in this case, data center load)."[377]

In rebuttal, Mr. Bilyeu testified that it is not necessary to include a high load growth sensitivity in the amended REP and that such scenarios are better suited for modeling in IRPs.[378] He added that the impact of data centers is uncertain, and that legislation permits utilities to file expedited cases if significant changes occur.[379] Mr. Bilyeu also emphasized that the Commission, in its April 25, 2024, Order in Case No. U-21568, stated that IRPs are the most appropriate venue to consider generation diversity and renewables planning, and that amended REPs should reflect the assumptions included in a utility's most recently approved IRP.[380] Mr. Bilyeu further emphasized that as recognized by Ms. Glick, the renewable buildout from the 2022 IRP was sufficient for the company to meet

[375] 2 Tr 194.
[376] 2 Tr 195.
[377] 2 Tr 196.
[378] 3 Tr 320.
[379] 3 Tr 320.
[380] 3 Tr 320.

renewable portfolio standards in all years under the IRP's high growth scenario.[381] He added that the company would include an updated high growth scenario in its next IRP filing.[382]

Mr. Bilyeu testified that a high growth sensitivity is not included in the filing requirements for amended REPs adopted by the Commission in Case No. U-21568. He also asserted that new data centers would "not necessarily" increase the company's renewable portfolio standard requirements because data center customers could enroll in the company's VGP program, which would not increase renewable portfolio standard targets.[383]

2. Briefing

The company's briefing closely tracks Mr. Bilyeu's rebuttal testimony.[384] The company also argues that advocating for inclusion of a high load growth scenario in the current amended REP is different from advocating for such modeling in future REP applications. The company argues that if MEC-SC desired a high load growth sensitivity in the current amended REP, then their advocacy should have occurred in Case No. U-21568 which established filing requirements for amended REPs under PA 235.[385] The company explains that MEC-SC submitted comments in that docket, but did not advocate for high load growth sensitivity and thus should be estopped from advocating for one now.[386] The company contends that Ms. Glick's testimony is "not instructive for purposes

[381] 3 Tr 320.
[382] 3 Tr 320.
[383] 3 Tr 321.
[384] See generally DTE, 25-27.
[385] DTE, 25.
[386] DTE, 25-26.

of analyzing the reasonableness and prudence of the Company's forecasts in the currently pending Amended REP."[387] The company also asserts that a high-load growth sensitivity should not be required in future REPs because it would be duplicative and unnecessary in light of modeling requirements for IRPs.[388]

MEC-SC summarizes numerous points from Ms. Glick's testimony and reiterates that the Commission should recommend that the company should include a high load growth sensitivity in this filing and future REP filings to account for the emergence of data centers as a new customer type.[389] MEC-SC argues that while the REP filing requirements approved by the Commission in 2024 did not require a high load growth sensitivity, the Commission also stated that the elements in the filing requirements were intended to be initial guidance and are not necessarily exhaustive.[390] MEC-SC also contends that the cross-examination of company witnesses established that the company lacks objective, verifiable standards for inclusion of a large new facility in its load forecast such that the company should be required to develop and disclose the objective standards that it uses to include new large customers in its load forecast.[391] While MEC-SC states it is "not in a position to prescribe the details of those standards," it provides the following examples of potentially applicable standards: "site control; municipal or zoning approval; a business plan; architectural or technical schematics for the facility;

[387] DTE, 26.
[388] DTE, 26-27.
[389] MEC-SC, 24.
[390] MEC-SC, 29 (citing Case No. U-21568, May 23, 2024, Order, p 3).
[391] MEC-SC, 30-31.

procurement by the customer of materials & equipment to build the facility; a contract with the utility; or a deposit paid to the utility."[392]

In reply, the company argues that it properly relied upon the Commission's filing requirements when developing its sales forecast, reiterates that its forecast complies with those requirements, and asserts that it would be inappropriate to expand the scope of the filing requirements by requiring a high load growth sensitivity in this case.[393] The company again argues that modeling of high load growth scenarios should be conducted during the IRP process and contends that to require such modeling in this case would "result in significant administrative inefficiencies" that could "jeopardize timely implementation of the Amended REP."[394] According to the company, if the Commission considers expanding the scope of the filing requirements for future amended REPs, the appropriate forum for doing so would be Case No. U-21568, where those requirements were established.[395] The company states, "Electric utilities must be able to rely upon the Filing Requirements, not as mere suggestions with vague parameters, but as well-defined, prescriptive requirements for developing and proving the reasonableness of their amended REPs."[396]

The company defends the accuracy of its sales forecast as being reasonably based on information that was available to the company when it prepared its amended REP.[397] The company states it would be premature, even now, to include data center load

[392] MEC-SC, 31.
[393] DTE Reply, 15, 17.
[394] DTE Reply, 16, 18.
[395] DTE Reply, 18.
[396] DTE Reply, 18.
[397] DTE Reply, 16-17.

in its forecast because such load is "too uncertain and undefined."[398] The company describes MEC-SC's evidence regarding potential data center load as "speculative and unreliable" and specifically criticizes the use of projections from PJM in Virginia as an "outlier example" that is inapplicable to the company.[399] The company again contends that its amended REP meets PA 235's renewable portfolio standard based on the high load growth forecast from the company's 2022 IRP.[400] Further, while the company sees no need to include data center load in this amended REP, it notes that utilities are permitted to file expedited cases and therefore concludes that "the statutory scheme already provides for adequate remedies if significant changes occur that impact an approved amended REP."[401]

The company takes issue with the examples of objective and verifiable standards that MEC-SC says the company should use when determining whether to include new large customers in its load forecast, arguing that the company is not privy to most of the information contained in those examples and further questioning whether the information is indeed objective.[402] The company also emphasizes that based on available information, none of those examples apply to potential data centers; "This strongly supports why inclusion of potential data center load and/or prospective customers is currently too uncertain."[403]

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[398] DTE Reply, 16-17.
[399] DTE Reply, 17-18.
[400] DTE Reply, 16, 18.
[401] DTE Reply, 17.
[402] DTE Reply, 19.
[403] DTE Reply, 19.

MEC-SC continues to argue that the company's sales forecast should account for "clear changes in the market" concerning data centers and that the Commission should assess the reasonableness and prudence of the company's amended REP "in light of recent market developments."[404] MEC-SC also states that the company provides no explanation in support of its position that high load scenarios are better suited for modeling in IRPs rather than REPs.[405] MEC-SC concludes "there is nothing preventing DTE from including high load growth sensitivities in all future REP load forecasts, and doing so would allow the Company to adequately account for new developments and changes in the market since the prior IRP load forecast."[406]

3. Conclusion and Recommendation

This PFD rejects MEC-SC's contention that the sales forecast presented in this case is deficient because it fails to contemplate potential increased load from data centers. It should first be noted that the Commission's amended REP filing requirements do not require specific consideration of data centers as part of the sales forecast.[407] Also contrary to MEC-SC's proposal, the Commission has expressed its preference that "amended REPs should reflect the assumptions included in the providers' most recently approved IRP."[408] While the initial amended REP after PA 235 need not align with the previous IRP,[409] this PFD does not find any need to invoke that exception here. Indeed, as MEC-SC acknowledges, the renewable build out that was approved in the 2022 IRP

[404] MEC-SC Reply, 24.
[405] MEC-SC Reply, 25.
[406] MEC-SC Reply, 25.
[407] The filing requirements are attached as Exhibit A to the May 23, 2024, order in Case No. U-21568.
[408] Case No. U-21568, Order, April 25, 2024, p 19.
[409] Case No. U-21568, Order, April 25, 2024, p 20.

is sufficient to comply with the new renewable energy standard under the company's current high growth forecast.[410] And while MEC-SC's evidence concerning potential load growth from data centers is relevant and must not be dismissed, this PFD finds compelling the company's argument that its sales forecast was reasonably based on information known to the company at the time of filing its amended REP and the impact of data centers is too uncertain to render that forecast unreasonable in the context of this case.

In concluding that the IRP is the ideal forum for modeling alternative load scenarios, this PFD further recommends that the company be required in its next IRP to explicitly address the potential impact of data centers and other high-load customers when formulating its load projections. In doing so, the company should state the criteria used for determining whether to include a new or expanding large customer in its forecast. The company expects to file its next IRP by December 2026. In the meantime, The Commission should recommend that if significant developments necessitate changes to the company's REP, the company should file an expedited case under MCL 460.1022(4).

K. Curtailment of Renewable Energy

1. Testimony

Mr. Jacobs defined "curtailment" as "the reduction of a renewable facility energy generation output below what it would otherwise be capable of, with a given wind speed or irradiance."[411] He asserted that co-locating energy storage with renewables may allow the storage of energy that would otherwise be lost to curtailment.[412] Mr. Jacobs testified that curtailment will persist from the oversupply of generation at times and that planning

[410] See 2 Tr 179, 193.
[411] 3 Tr 623.
[412] 3 Tr 623.

in advance is required to avoid overwhelming the ability of the grid to accommodate renewable deployment on the scale needed to reach the REP's 2030 goal.[413]

Mr. Jacobs testified that MISO undertook a multi-year Renewable Integration Impact Assessment (RIIA) to determine how the growth of renewables would affect the power grid.[414] He explained that the RIIA showed that curtailment is a certainty in high renewable energy resource mixes, with pronounced curtailment expected once renewables reach 30% penetration; indeed, he defined the 30% level as an "inflection point for grid planning and operations."[415] Mr. Jacobs testified that the RIIA study found that once renewables reach 30%-40% penetration, existing infrastructure becomes inadequate and additional infrastructure is needed to maintain adequate resource distribution across MISO.[416] He opined that within the next five years, the company will reach this inflection point given its plan to increase renewable generation resources.[417]

Mr. Jacobs argued that the company needs to prepare for curtailment risk as described in the RIIA, and that it "needs to be clearer about the causes of curtailment and then develop strategies to address the risk."[418] He testified that both MISO and the company recognize transmission and storage as means of reducing curtailment, but he added that the company states that is not able or has not yet begun to estimate or manage the risks of curtailment.[419] Mr. Jacobs explained that the exhibits and projections in the

[413] 3 Tr 624.
[414] 3 Tr 620-621.
[415] 3 Tr 624, 625.
[416] 3 Tr 626.
[417] 3 Tr 626.
[418] 3 Tr 626.
[419] 3 Tr 626, 627.

company's amended REP show no indication of a growing risk of curtailment for renewable resources.[420]

Mr. Jacobs stated that the company requires MISO interconnections to its renewable energy resources to use Network Resource Interconnection Service (NRIS) because it will lead to less curtailment than the alternative, less expensive connection service.[421] But Mr. Jacobs asserted that "there is only a tenuous link between an NRIS interconnection study and an assessment of curtailment risk."[422] He explained that a NRIS interconnection study only examines the period of peak demand in the year the new generation comes online, and it does not examine all other hours of the year when electrical load is less.[423]

Mr. Jacobs explained that "solar clipping" occurs when solar panel capacity is overbuilt compared to a facility's inverter such that any energy output exceeding the inverter's output is lost.[424] He testified that the company's amended REP describes how capturing energy lost to solar clipping would be beneficial, but the REP does not refer to any situation in which the company evaluated or will use such a design.[425] He asserts that the company has not quantified the benefits of co-locating storage with renewables, although the company references how storage could prevent solar clipping and curtailment.[426] Mr. Jacobs expressed concern that the company did not indicate that it is projecting curtailment at its proposed Pine River LDES facility and has not made the case

[420] 3 Tr 627.
[421] 3 Tr 628.
[422] 3 Tr 628.
[423] 3 Tr 628-629.
[424] 3 Tr 629.
[425] 3 Tr 630.
[426] 3 Tr 630.

that it will use the LDES deployment to reduce curtailment.[427] He testified that the company did not include any quantification of benefits from energy storage in this docket and instead referred to its analysis in its previous IRP case, U-21193.[428] However, he testified that upon examining that analysis from the IRP, it did not include a discussion of renewable generation curtailment.[429]

Mr. Jacobs testified that "going forward, [the company] appears to underestimate or misinterpret the risks of curtailment and thus make an overestimate of how many RECs will be produced from its renewable energy supply resources absent plans for increased storage capacity."[430] He expressed similar concerns that the company is not making adequate preparations to ensure that generation planned in the REP will be able to be produced as forecasted without additional transmission resources beyond what it obtains through the interconnection process.[431] Indeed, he testified that power flow modelling indicated that "significant new transmission investment is required" to prevent curtailment for even one-half of the amount of renewables that the company plans to add under the amended REP.[432]

Mr. Jacobs concluded that the company "neglected to make a reasonable analysis of the risks of curtailment to the portfolio of renewable generation in the REP."[433] He recommended that in future REPs, the company should adequately analyze the risks associated with curtailment and transmission constraints and should also include a

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[427] 3 Tr 631.
[428] 3 Tr 632.
[429] 3 Tr 633.
[430] 3 Tr 634.
[431] 3 Tr 634.
[432] 3 Tr 638.
[433] 3 Tr 639.

comprehensive strategy for co-location of storage with renewables.[434] He also recommended that the company should review MISO's RIIA report regarding challenges posed by increased renewable generation and should explore ways to find "synergies of analysis" between the IRP and REP process.[435]

In rebuttal, Mr. Bilyeu disagreed with the concerns expressed by Mr. Jacobs regarding the company's IRP, transmission risks, the role of NRIS in mitigating curtailment, and RECs. Mr. Bilyeu stated that the company's 2022 IRP accounted for curtailment of renewables, even if it was not explicitly discussed given its minimal impact, because the EnCompass modelling software used for the simulation included projected curtailment.[436] He added that the company submitted a report prepared by ITC detailing transmission system upgrades needed to support the IRP's proposed course of action.[437] Mr. Bilyeu testified that contrary to Mr. Jacobs' explanation, MISO conducts annual NRIS studies to ensure that once a project is in commercial operation, it can maintain NRIS value thereby minimizing risks beyond the initial interconnection system impact studies.[438] He further argued that Mr. Jacobs failed to provide any support for his claim that curtailment might result in the company falling short of its RPS requirements and that Mr. Jacobs ignored the carry-over balance of RECs that could be used as a hedge against any impacts from curtailment.[439] Mr. Bilyeu stated that the amended REP was not the appropriate place to model curtailment, but he agreed with Mr. Jacobs that, in accordance

[434] 3 Tr 639, 640.
[435] 3 Tr 640.
[436] 3 Tr 322.
[437] 3 Tr 323.
[438] 3 Tr 323.
[439] 3 Tr 323-324.

with the Commission's April 25, 2024, Order in Case No. U-21568, the IRP is the best venue in which to model curtailment.[440]

In his rebuttal, Mr. Harlow similarly stated that curtailment should be modeled by the company but that any curtailment analysis should be done in the company's next IRP scheduled to be filed in 2026.[441]

2. Briefing

The company asserts that it agrees with Staff that the amended REP is not the proper case to model curtailment. The company also agrees with Mr. Jacobs that curtailment risks should be modeled in the company's next IRP and that synergies should exist between IRPs and amended REPs, "so long as the synergism follows the contours and sequencing established in the April 25 Order."[442] The company states that it will continue to assess curtailment risk in the next IRP and that it will ensure alignment with the build plan included in the amended REP which aligns with the Commission's directive in its April 25 Order stating that Amended REPs should be informed by the company's most recent IRP.[443]

Staff states that it "does not necessarily disagree" with CEO witness Jacobs that his concerns regarding curtailment "may be valid[;]" however, Staff maintains that curtailment should be addressed in the company's next IRP rather than in the current REP.[444]

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[440] 3 Tr 324.
[441] 2 Tr 37.
[442] DTE, 65. Note that this statement refers to the Commission's April 25, 2024, Order in Case No. U-21568, which established filing requirements for amended REPs.
[443] DTE, 65.
[444] Staff, 15.

The CEO briefing repeats and delineates the concerns expressed by Mr. Jacobs in his direct testimony.[445] The CEO reiterates their recommendations that focus on analyzing curtailment and transmission constraints in future REP cases as well as finding synergies between IRP and REP cases.[446]

Staff and the CEO did not file reply briefs, but in its reply the company maintains that the amended REP is not the appropriate case to model curtailment and that the company agrees that curtailment risks should be modeled in its next IRP.[447]

3. Conclusion and Recommendation

This PFD appreciates the thoughtful concerns raised by CEO concerning the risk that curtailment poses to the company's ability to reach its RPS goals. However, this PFD agrees with the company and Staff that risks associated with curtailment and transmission constraints are better addressed in an IRP proceeding rather than in REP proceedings because IRP proceedings have a broader focus and take a more holistic approach to planning for the future. Accordingly, this PFD recommends that the Commission direct the company to place an increased focus on analyzing the risks of curtailment and transmission constraints in its next IRP. This recommendation should not be controversial because the company already stated that it agrees that curtailment risks should be modeled in its next IRP.[448] This PFD also agrees with CEO that the Commission should direct that in undertaking that future analysis, the company should analyze co-located storage as a method of reducing curtailment and that the company's curtailment analysis

[445] CEO, 5-12.
[446] CEO, 12.
[447] DTE Reply, 39.
[448] See e.g. DTE Reply, 39.

should be informed by, among other sources, MISO's RIIA or similar future MISO reports that study the challenges associated with the increased share of renewable energy resources.

Finally, this PFD appreciates the CEO's recommendation that the Commission should provide guidance regarding ways to find synergies of analysis between IRP and REP proceedings. However, this recommendation does not appear to be directly tied to any explicit, actionable request as to what specific guidance should be provided. In any event, this PFD notes that the Commission has already provided some direction regarding the interplay and alignment of IRPs and REPs in its April 25, 2024, Order in Case No. U-21568.[449]

IV.

CONCLUSION

This PFD recommends finding that the company's amended REP is consistent with the purposes set forth in MCL 460.1001, meets renewable energy credit standards, and is reasonable and prudent, and therefore meets the standards for approval under MCL 460.1022(5) on the condition that the company consents to the changes and recommendations laid out in this PFD.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

James M. Varchetti

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James M. Varchetti
Administrative Law Judge

Issued and Served:
February 28, 2025

[449] See Case No. U-21568, April 25, 2024, Order, p 19-20.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

STATE OF MICHIGAN)
) SS.
County of Ingham)
_____)

Case No. U-21662

PROOF OF SERVICE

Meaghan Dobie being duly sworn, deposes and says that on February 28, 2025, she served a copy of the attached Notice of Proposal for Decision and Proposal for Decision via email and/or first-class mail, to the persons as shown on the attached service list.

Meaghan Dobie

Subscribed and sworn to before me this
28th day of February 2025.

Angela P. Sanderson
Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
My Commission Expires May 21, 2030

Case No. U-21662
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